STATE OF CALIFORNIA

**Energy Resources Conservation
And Development Commission**

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Preparation of the 2005	)	
Integrated Energy Policy Report	)	

REBUTTAL TESTIMONY FOR AUGUST 24, 2005 COMMISSION HEARING ON IOU APPEALS OF EXECUTIVE DIRECTOR'S AGGREGATION PROPOSAL

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REBUTTAL TESTIMONY

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Introduction

On July 8, 2005, Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) filed testimony in support of their appeals of the proposed release of aggregated summaries of data filed with the California Energy Commission (Energy Commission) in the 2005 Integrated Energy Policy Report (Energy Report) proceeding. This testimony, including eight attachments addressing specific issues in more detail, is provided as rebuttal to the utility testimony. A list of attachments is included as Table 1 at the end of this testimony.

The utilities filed the following testimony:

- PG&E
    - Testimony of Roy Kuga, Vice President, Gas and Electric Supply
    - Declaration of James D. Shandalov, originally filed with the California Public Utilities Commission (CPUC) in Rulemaking 01-10-024 on March 1, 2004
- SCE
    - June 17, 2005, Letter from Beth A. Fox, Senior Attorney, to Scott Matthews, Acting Executive Director of the Energy Commission, appealing the proposal to release the aggregated summaries (including the proposal and cover letter as Appendix 1)
    - A May 20, 2005, document providing the preliminary joint views of the three utilities to a preliminary aggregation proposal prepared by Energy Commission staff (Appendix 2 to the Fox letter)
    - Declaration of Charles R. Plott dated June 17, 2005 (Appendix 3 to the Fox letter)
    - “Forced Information Disclosure and the Fallacy of Transparency in Markets” by Timothy N. Cason and Charles R. Plott (Exhibit A to the Plott declaration; referred to here as the Plott study)
- SDG&E
    - Declaration of Mike McClenahan, dated July 8, 2005

The utility testimony generally maintains that the release of the aggregated summaries of data proposed by the Energy Commission staff would necessarily result in higher prices for their customers. Central to the utility arguments is their claim that providing additional information to potential suppliers of electricity necessarily allows those parties to extract higher prices.[1] The utilities provided two

[1] The utility apply these basic arguments to their sales of electricity as well as to their purchases, arguing that when they look to sell, potentially buyers will lower their bids if they have additional information about the utilities position. In this rebuttal testimony, we will refer solely to the utilities’ potential purchases of electricity, but our testimony applies equally to utility sales.

main pieces of evidence to support this position. The first is the Plott study, which Dr. Plott asserts demonstrates “that requiring Investor-Owned Utilities (IOUs) to reveal their net-short position to power suppliers will result in higher electricity prices for the public.” (Plott declaration, paragraph 4) The second is the market manipulation that occurred during 2000 and 2001 in California. According to the utilities, this evidence demonstrates that providing generators additional information today will lead to the same type of market manipulation seen in the study and in 2000 and 2001. However, both the Plott study and the analogy with 2000/2001 ignore the specifics of the aggregation proposal under discussion[2] as well as the current nature of the California electricity market.

Beyond that general position, which underlies virtually all of the utility testimony and was elaborated on by some witnesses, the various pieces of utility testimony also spell out a number of arguments why different portions of the proposed aggregation proposal are particularly sensitive. In some instances, these arguments apply across the utilities. However, the three utilities appealed different portions of the aggregation proposal, and some of the individual utility testimony claims that confidentiality is required for information that other utilities are willing to release. The following summarizes the more specific assertions raised in individual pieces of utility testimony that are addressed in this rebuttal testimony.

- Releasing information that reveals the value a utility places on various goods and services causes damaging effects. (SDG&E, McClenahan)
- PG&E is vulnerable to harm from the release of seasonal data. (PG&E, Kuga)
- The request for offer (RFO) process provides adequate planning information. (PG&E, Kuga)

In this rebuttal testimony, we first discuss the assumption underlying most of the utility testimony: that market manipulation will result from the proposed release of the aggregated summary tables. We then address some of the specifics of the information that would be released under the aggregation proposal, the nature of information already available to market participants, and the practices of other utilities in the western United States that participate in the same electricity markets as these utilities. Table 2 provides a summary of the IOU appeals of various Executive Director aggregation proposals and the main arguments of staff in rebuttal.

[2] Energy Commission staff published summary tables for those portions of the aggregation proposal that none of the utilities appealed (CEC Staff Paper, “Resource Plan Aggregated Data Results,” CEC Report No. CEC-150-2005-001, June 2005). It is useful in evaluating the IOU testimony to consider the tables included for the Sacramento Municipal Utility District (Tables 39 through 46) and Los Angeles Department of Water and Power (Tables 47 through 50), which include energy and capacity tables based both on planning area aggregations and utility-customer-specific information. Quarterly tables were not produced in this paper but could have been produced for both SMUD and LADWP, since they did not request confidentiality for their filings.

Market manipulation

A key assumption implicit in the utility position is that a limited number of electricity providers will be negotiating with the utilities and will be able to exercise market power through actual or tacit collusion in a manner similar to what happened during the 2000/2001 crisis. For example, Kuga states "[t]elling the market exactly how much is needed would give suppliers an unfair advantage in pricing the last increment needed…." (Kuga declaration, p. 2) While this assertion makes sense if the utility were dealing with a single supplier, when there are competing suppliers and the potential for entry by new suppliers, the collective action by the 'suppliers' described in the utility testimony would amount to collusion. Similarly, SCE witness Cini recounts the California experience with the 2000/2001 crisis, and then asserts that "[i]f a market participant or market participants became aware of the magnitude of SCE's 'short' position for any particular period, that market participant or all market participants collectively could and would charge a higher price…." (Cini declaration, paragraph 14)

To address this concern, Julia Frayer has prepared a comparison of the current California electricity market to the market during the 2000/2001 crisis that demonstrates that the utility fears in this regard are groundless.[3] That testimony shows that the current market environment, market structure, and regulatory framework are significantly different than those conditions that prevailed in 2000 and 2001.[4] The current industry structure in California lacks the prerequisite conditions for the exercise of market power through tacit collusion or some other form of oligopolistic behavior in the context of long-term procurement of electricity. Without collusion between potential suppliers, release of the type of planning information contemplated in the aggregation proposal will not lead to higher prices in the long term procurement process of the IOUs. The type of long-term planning data is not the type that would be the basis of any collusion, and the repeated assertions in the utility testimony that release of this data will lead to a repeat of the 2000/2001 crisis are without foundation.[5] In fact, the release of the aggregated summary tables is more likely to foster competition in the long term market by helping signal the

[3] See Attachment A, *Analyzing the potential for the exercise of market power in the long term procurement of energy in California*, prepared by Julia Frayer, London Economics.

[4] It is also worth noting that the type of planning data the utilities claim would provide the necessary tools for the type of market manipulation that occurred during the crisis was not actually publicly available in 2000 and 2001. The repeated suggestions in the utility testimony that release of the summary tables proposed by staff would lead to a repeat of the electricity crisis might lead a reader to believe that it was the availability of this type of information that lead to market manipulation during the crisis. That was not the case.

[5] The only evidence provided beyond general assertions is the Plott study. That study is based on provision of information in a manner extremely different from the one time release of long-term planning data contemplated by the aggregation proposal, and the study design does not provide a good model for the current California electricity market. These limitations of that study are discussed in staff's initial testimony. See, for example, Jaske's direct testimony at p. 12, and Frayer's direct testimony at pp. 18-19. In addition, Attachment B, *IOU long term procurement, RFOs, auction theory and information release policy*, prepared by Julia Frayer, London Economics also notes additional considerations with regards to Dr. Plott's study.

optimum location and timeframe for additional entry. The beneficial signaling properties of the aggregated summary tables are either not addressed or wrongly dismissed by the IOUs in their appeals.

In fact, given the current market structure that largely relies on competitive solicitations, provision of additional information to all parties is likely to improve the competitiveness of the market. As discussed by Ms. Frayer in Attachment A, auction theory in economics suggests that in competitive auction settings, such as the utility RFOs, a lack of adequate information will lead some bidders to focus their strategies on attempting to gather information or to not participate because of the fear that other bidders are somehow better positioned to win the RFOs. One example of the former discussed by Ms. Frayer is the use of ‘hockey stick’ bidding. However, when an adequate base of common information is available to a sufficiently large pool of bidders, these bidders shift the emphasis of their bidding strategy from attempting to discover hidden information to competing amongst themselves. The result of this competitive focus will lead to downward pressure on prices over the long term. Furthermore, due to the diverse set of market participants in California’s market, there is a varying level of sophistication among potential bidders. Release of the information embodied in the aggregated summary tables will substitute for the existing private information of the more sophisticated suppliers and level the playing field among all the bidders and will unambiguously lead to more aggressive competition in long term procurement processes. The underpinning logic for such consequences is further discussed in Attachment A and Attachment B.

Several additional factors reinforce this point. First, the aggregation proposal in dispute would only release information for the period 2009 through 2016. While there may be limited ability for new suppliers to enter the market in the short term and hence more ability of suppliers to modify prices in response to specific situations of an IOU needing to buy power, parties bidding to supply electricity for 2009 and beyond will have to be aware that additional parties may be able to enter the market by 2009. While Kuga has suggested that the utility RFO process “already tells the marketplace what resources are needed and when.” (Kuga declaration, p. 2) The short time period for suppliers to respond to utility RFOs means that only suppliers with projects well into the planning process will be able to respond.[6] Release of longer term planning data provides clearer signals to suppliers when and where to focus their project development activities.

The utilities claim that revealing their current views of their annual and quarterly net open positions for 2009 or later years will leave them vulnerable to unreasonably high bids. For example, Kuga states that “telling the market exactly how much is needed would give suppliers an unfair advantage in pricing the last increment of need.” (Kuga declaration, p. 2) This only makes sense if the utility is in a position that it must fill all of its need in a single bidding process. Because of the heavy

[6] The current procurement process and recent IOU RFO activity is discussed in Attachment B, *IOU long term procurement, RFOs, auction theory and information release policy*, prepared by Julia Frayer, London Economics.

reliance on day-ahead and hour-ahead markets in 2000 and 2001, this was a very real concern at that time. Unlike 2000, the IOUs currently are operating in a regulatory environment that encourages long-term procurement and have many viable alternatives to fulfill their long-term needs in the future. With the rules in place today, the utilities are already contracting for supplies for 2009 and beyond.[7] If a bidder attempts to demand an unreasonable price for "the last increment of need" in 2009 or 2016, the utility will be in a position to reject that offer and fill that need through later RFOs or negotiations.[8]

The utility testimony also fails to acknowledge the degree to which this ongoing procurement provides the utilities with the ability to manage their risks. Attachment B summarizes the procurement authority and makes clear that the IOUs do not need to rely on any single RFO or set of bilateral negotiations. They have the ability to arbitrage between spot and forward markets, as well as initiate utility investment in new generation. Subject to deliverability, they can decide to procure from sources outside their service territory, and potentially outside the state. The substitutability of these alternatives and the multi-dimensional aspect of future procurement clearly characterize the long term needs of the IOUs as fairly elastic. This elasticity further safeguards the IOUs and their ratepayers against potential exercise of market power by suppliers at any point in time or during any particular procurement process.

Finally, most of the utilities in the western market provide significantly more planning information than would be released by under staff's aggregation proposal. The utility testimony, which consistently argues that release of the type of planning data proposed by staff would place them at a competitive disadvantage, ignores the fact that almost every other utility operating in the same western electricity market regularly makes public the data they insist is a trade secret. Dr. Michael Jaske discusses the availability of the data from the region's major utilities in Attachment C, and concludes that there are no unique factors to justify different practices by California IOUs.[9]

Data availability

SDG&E witness McClenahan testifies that "the information counterparties require to gain this competitive advantage falls into two general categories: (1) the information that allows competitors to know, not necessarily with exactitude but even simply with reasonable certainty, what their potential counterparty's position is (short, as a buyer in the market, or long, as a seller) and a feel for the magnitude of that need to buy or sell; and (2) the information that informs a competitor of the value that its potential

[7] A comparison of the 2000/2001 market structure with that in place today is provided in Attachment A, *Analyzing the potential for the exercise of market power in the long term procurement of energy in California*, prepared by Julia Frayer, London Economics.

[8] In a circumstance where there are multiple suppliers, of course, the ability of the suppliers to determine the "last increment of need" would require some form of collusion.

[9] See Attachment C, *The myth of California IOU uniqueness*, prepared by Dr. Michael Jaske, Energy Commission staff.

counterparty places on various goods or services." (McClenahan declaration, pp. 2-3) Mr. McClenahan further states that "any data that reveals either side of the equation (net short + resources = load), either on its own or in combination with other data, should be maintained as confidential. A non-exhaustive list of such data includes: granular load data, load shapes, capacity factors of dispatchable units, terms and conditions of supply contracts." (*Ibid*., p. 3)

In evaluating these arguments, it is important to be aware of the fact that a great deal of information is already available from other sources, including significant amount of historic data on all of the items on Mr. McClenahan's list. This wealth of available information is much more useful to any electricity market participant in developing a clear picture of the utilities' positions in the market and the value they currently place on various electricity products, especially for the short term period. It is during this short-term period when the exercise of market power may be more likely, due to fixed number of suppliers (as a result of the timeframe necessary for new participants to enter particular markets[10]) and the reduced elasticity of the IOUs in purchasing power as real time approaches. Among the most relevant data sources are the Electronic Quarterly Reporting (EQR) system maintained by Federal Energy Regulatory Commission's (FERC); historic hourly demand data reported to FERC on Form 714; hourly production data for most larger utility generation plants (greater than 73 MW) and industrial steam plants greater than 2.9 MW available from the U.S. Environmental Protection Agency (US EPA) Continuous Emission Monitoring System (CEMS);[11] and monthly production and fuel consumption data on a plant or unit level through mandatory filings made by power plant operators to the federal Energy Information Agency (EIA) on Form 906 (monthly production and fuel consumption) and Form 860 (generation status).

The FERC EQR data is described in detail in Attachment E.[12] This database, which is available to the public through the FERC website,[13] provides detailed information on both short-term and long-term contracts and transactions for all market participants on a quarterly basis. The information provided includes contract start and end dates, product, price, and delivery locations, and covers all contracts effective during the reporting quarter under FERC jurisdiction, and any transactions that occurred during the quarter associated with the FERC jurisdictional contracts. This data base provides market participants, particularly those with the resources to mine the extensive database, a much more direct indication of the value that the utilities are placing on different electricity products: the cost of a specific contract and the term and energy associated with it. This information allows other parties to

[10] A lengthy time period is needed to plan, license and construct electric power plants. As the principal power plant licensing agency in California, The Energy Commission has detailed knowledge of the timelines required. See Attachment D, *Power plant project development timelines in California, 1997-2005*, prepared by Dr. Kevin Kennedy, Energy Commission staff.

[11] *See* http://www.epa.gov/ttn/emc/cem.html

[12] See Attachment E, *Guide to the FERC Electric Quarterly Reports: availability of specific contract and transaction data*, prepared by Julia Frayer, London Economics.

[13] See http://www.ferc.gov/docs-filing/eqr.asp

construct the IOU "value curve" by examining what the IOUs have paid recently under various circumstances. That information would allow a generator to forecast what the utilities are willing to pay under comparable circumstances. In addition to this historic contract and transaction data, a variety of public information sources are available on forward electricity prices, which are summarized in Attachment F.[14]

In considering Mr. McClenahan's second point in particular (revealing the value that the utility places on various goods and services would provide others a competitive advantage), it is important to keep in mind that the aggregation proposals would not directly reveal any historic or forecast price information. On the other hand, public information sources like the FERC EQR database provide a large amount of information on the prices recently paid by SDG&E and other utilities for various products and for the value the market places on various products into the future.

The EIA Form 906 data is also described in detail in Attachment G.[15] This database, which is available through the EIA website,[16] provides detailed monthly summaries of generation and fuel use from most large power plants. This data, coupled with other EIA submissions (such as the Form 860), allows calculation of the capacity factors of most power plants, including utility-owned units on a monthly and annual basis.

This data is also important relative to PG&E's claims of particular sensitivity to release of quarterly data due to their reliance on seasonally variable wind and hydro facilities. The EIA Form 906 data includes detailed historic information on the monthly energy production from PG&E hydro facilities, as described in more detail in Attachment G.[17] This actual historical data will give other market participants a robust basis for estimating how the wind and hydro units PG&E is concerned about operate seasonally over time.

Also relevant to PG&E's claims that it is particularly sensitive to the release of quarterly data is the recent action by the CPUC. Under the terms of the May 9, 2005, administrative law judge (ALJ) ruling in R.04-04-025, in addition to extensive details on a quarterly basis for historic resource plan data, the utilities were ordered to make publicly available the following forecasts:

- quarterly energy demand forecasts for the years 2005 through 2010;
- adjustments to those forecasts for mandated programs such as energy efficiency and demand response; and
- quarterly generation forecasts of utility owned generation facilities by type (e.g. hydro, nuclear) for 2005 and 2006.

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[14] See Attachment F, *Availability of market price information for the wholesale electricity market in the Western Electricity Coordinating Council*, prepared by Julia Frayer, London Economics.

[15] See Attachment G, *Overview of the availability of detailed monthly production data from hydroelectric facilities*, prepared by Julia Frayer, London Economics.

[16] http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html

[17] See Attachment G, *Overview of the availability of detailed monthly production data from hydroelectric facilities*, prepared by Julia Frayer, London Economics.

The utilities have generally maintained that near term forecasts are more sensitive than longer term forecasts, so this mandated public release of near term quarterly energy forecasts suggests that the summaries of the energy forecasts and projections for 2009 through 2016 in dispute here could be released without causing any additional harm. The significance of this data release is discussed in more detail in Attachment H.[18]

Conclusion

This rebuttal testimony provides staff's response to the points made by the IOUs in their July 8, 2005 testimony. Staff believes that the Executive Director's aggregation proposal strikes a reasonable balance between the IOU desires to protect their ratepayers from abuse of market power and the Commission's needs to provide planning data to the public to facilitate good public policy. By aggregating from monthly data to quarterly and annual values, by summarizing from specific resources to resource type subtotals, and by agreeing to not release data prior to forecast year 2009, the aggregation proposal eliminates any trade secret aspects of the original detailed data submissions. The IOU appeals fail to acknowledge that their desired restrictions fly in the face of conventional practice among Western utilities. The IOUs have not demonstrated that their circumstances are unique among Western utilities who all purchase from the same market of independent generators and other utilities. The IOUs have not acknowledged that there are very detailed sets of data about actual market transactions that give far more specific clues about what purchases IOU are likely to make and how much they are willing to pay for them than the general planning data at issue here. Finally, the IOUs fail to acknowledge that there are positive benefits to their own ratepayers that accrue from releasing IOU-specific planning data by providing more accurate signals to the generator community that needs long lead times to be able to plan, license, and construct new power plants. The IOU appeals should be rejected.

[18] See Attachment H, *Demand forecast and resource plan data: disclosure mandates of the CPUC in R.04-04-025*, prepared by Dr. Michael Jaske, Energy Commission staff.

Table 1. List of attachments

Attachment A	*Analyzing the potential for the exercise of market power in the long term procurement of energy in California*, prepared by Julia Frayer, London Economics.
Attachment B	*IOU long term procurement, RFOs, auction theory and information release policy*, prepared by Julia Frayer, London Economics.
Attachment C	*The myth of California IOU uniqueness*, prepared by Dr. Michael Jaske, Energy Commission staff.
Attachment D	*Power plant project development timelines in California, 1997-2005*, prepared by Dr. Kevin Kennedy, Energy Commission staff.
Attachment E	*Guide to the FERC Electric Quarterly Reports: availability of specific contract and transaction data*, prepared by Julia Frayer, London Economics.
Attachment F	*Availability of market price information for the wholesale electricity market in the Western Electricity Coordinating Council*, prepared by Julia Frayer, London Economics.
Attachment G	*Overview of the availability of detailed monthly production data from hydroelectric facilities*, prepared by Julia Frayer, London Economics.
Attachment H	*Demand forecast and resource plan data: disclosure mandates of the CPUC in R.04-04-025*, prepared by Dr. Michael Jaske, Energy Commission staff.

Table 2. Summary of IOU appeals and principal rebuttal points

Temporal aggregation	LSE resource aggregation	Type	IOU positions	Principal points in staff rebuttal
Annual	1. IOU bundled-customer specific results; report individual scenarios	Capacity	PG&E, SCE, and SDG&E oppose	Virtually every major IOU in the West provides annual, resource-category capacity data and residual needs on an annual basis. Disclosing capacity balances is actually more common than energy balances.[19] The purchase power patterns and hydroelectric generation exposure for California IOUs is no greater than that of many other utilities in the West.[19] Forward markets will work better if annual capacity and energy needs are revealed.[20]
		Energy	All IOUs accept	NA
	2. Planning Area Aggregation across LSEs; report individual scenarios	Capacity	All IOUs accept	NA
		Energy	All IOUs accept	NA
	3. Planning Area Aggregation Across LSEs; report range spanning scenarios (capacity only)	Capacity	NA	NA[21]

[19] See Attachment C, *The myth of California IOU uniqueness*, prepared by Dr. Michael Jaske, Energy Commission staff.

[20] See Attachment A, *Analyzing the potential for the exercise of market power in the long term procurement of energy in California*, prepared by Julia Frayer, London Economics.

[21] The aggregation proposed here can be readily constructed from the information that has been released in the summary tables for the individual scenarios for the planning area aggregation.

Table2 (continued). Summary of IOU appeals and principal rebuttal points

Temporal aggregation	LSE resource aggregation	Type	IOU positions	Principal points in staff rebuttal
Quarterly	1. IOU bundled-customer specific results; report individual scenarios	Capacity	PG&E, SCE, and SDG&E oppose	Many major IOUs in the West provide monthly, resource-category capacity data and residual needs. Forward markets will work better if quarterly capacity and energy needs are revealed.
		Energy	SCE and PG&E oppose	CPUC May 9, 2005 Ruling requires quarterly IOU bundled customer planning data disclosure for loads and utility-owned generation. PG&E provided more complete detail for 2005-2006.[22] FERC EQR and EIA 906 data provide monthly near-real time data that is more valuable in characterizing IOU purchase patterns than long term planning information.
	2. Planning Area Aggregation across LSEs; report individual scenarios	Capacity	SDG&E and PG&E oppose	Disclosure of IOU results means that PA disclosure follows, since planning area is less intrusive.
		Energy	PG&E opposes	Disclosure of IOU results means that PA disclosure follows, since planning area is less intrusive.
	3. Planning Area Aggregation across LSEs; report range spanning scenarios (capacity only)	Capacity	PG&E opposes	NA[23]

[22] See Attachment H, *Demand forecast and resource plan data: disclosure mandates of the CPUC in R.04-04-025*, prepared by Dr. Michael Jaske, Energy Commission staff.

[23] The aggregation proposed here can be readily constructed from the information that would be released in the summary tables for the individual scenarios for the quarterly planning area aggregation. As such, staff has not directly addressed this form of aggregation in its testimony.

Attachment A

Analyzing The Potential For The Exercise Of Market Power In The Long Term Procurement Of Energy In California

Prepared By Julia Frayer, London Economics.

Analyzing the potential for the exercise of market power in the long-term procurement of energy in California: ***why the release of the aggregated summary tables will not lead to a repeat of the 2000-2001 energy crisis or other market manipulation***

LONDON ECONOMICS

prepared by London Economics International LLC for the California Energy Commission

August 12, 2005

1 Introduction

In testimony supporting their opposition to the June 3, 2005 *Notice of Intent to Release Aggregated Data* (the "NOI"), the California Investor Owned Utilities ("IOUs") have protested that disclosing the identified information, even in its aggregated format, could lead to the potential manipulation of markets. The IOUs' assertions with respect to market power are captured in a statement by Roy Kuga, Vice President of Gas and Electric Supply for Pacific Gas & Electric Company ("PG&E"): "Knowing this information, market participants may be able to extract higher prices from us and potentially exercise market power in our competitive procurement processes, thus driving up costs to our customers and damaging the competitive functioning of California's energy markets."[1]

The IOUs have implied that a crisis, such as the one that occurred in California from May 2000 to May 2001, might occur again, should this information be disclosed. They claim that the release of the aggregated data tables would give suppliers an opportunity to "manipulate"[2] procurement outcomes and provide an unfair "competitive advantage"[3] so as to allow suppliers to extract market power-driven profits, as some energy suppliers did during the 2000-2001 period. Indeed, PG&E's witness Roy Kuga explicitly compares the current situation to the 2000-2001 timeframe.[4] However, this comparison is without any legitimate basis.

In this briefing paper, I provide rebuttal to the claim that the NOI could result in a repeat of the energy crisis that occurred in 2000-2001 or in the exercise of any other type of classic market power. Moreover, I contend that the NOI will help to bolster competitive forces in the California electricity market, leveling the playing field for all market participants and providing more accurate signals about future investment needs.

1 *See* Kuga at 1.

2 *See* PG&E Appeal at 2.

3 *See* McClenahan at 2.

4 *See* Kuga at 2.

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My paper is based on three principal arguments. First, the crisis that occurred in 2000-2001 is not likely to occur again because many elements of the market environment, the market structure and the regulatory structure that combined to lead to the 2000-2001 crisis have been permanently changed, as outlined below.

- The **regulatory framework** has changed to allow IOUs a number of buy-side options in purchasing energy, in contrast to the large percentage of short-term spot market procurement that occurred during the crisis. In addition, market power mitigation mechanisms have been put in place to adequately prevent the development of market power potential.
- The **market environment** has evolved with additional suppliers and a relative reduction in the reliance on hydroelectric resources as a result of new power plants built not only in California but elsewhere in the Western Interconnect. This has decreased concentration of a single type of supply resource in the market.
- The **market structure** has also changed. There is no longer a centralized spot market in California, but rather a residual imbalance market operated by the California ISO ("CAISO") and a vibrant, decentralized bilateral market. This new structure makes collusion among market participants more difficult. In addition, the addition of new generating capacity has de-concentrated the California generation sector.

Second, the IOUs' concerns about market manipulation as a result of the NOI are unfounded. No single supplier in the CAISO control area has more than 10% market share on a capacity basis.[5] The conditions for tacit collusion among a group of market participants are not in place in the current California landscape: suppliers cannot observe in real-time one another's prices, making punishment for departing from the collusive target unfeasible; suppliers in California do not have similar cost structures; and, there is not a high concentration of suppliers in the market to indicate potential market power concerns. In addition, the timeframe of the aggregated data tables covered by the NOI is for the 2009-2016 period, equivalent to the market for long-term energy, not the spot market or a short-term procurement process. In the long term, the IOUs' demand for electricity from any given supplier is elastic because the IOUs have many options for acquiring supply, including building their own capacity. Intuitively then, the exercise of market power over this long-term market is practically impossible because it would not be profitable.

Third, the information that the NOI would ultimately release will only help improve competition within this context through leveling of the playing field for suppliers (by granting *all* market participants access to the same information and thus dampening resultant bidding strategies used to ascertain this same information and eliminate uncertainty) and by signaling the need for new generation and demand-side management.

5 Federal Energy Regulatory Commission ("FERC") *2004 State of the Market Report*, p. 72.

2 Consideration of relevant economic theory

As much of my discussion in subsequent sections relies on basic tenets of economic theory, I provide below a brief review of important, relevant economic principles, and illustrate them in the context of the California market. The IOUs claim that the release of the NOI aggregated data tables could result in a manipulation of the market by suppliers resulting in prices that are higher than competitive levels. However, as I will explain in this briefing paper, there is no underlying economic rationale or empirical evidence to support these claims.

Market power is the ability to maintain prices above competitive levels for sustained periods of time and will result in entities that can sustain higher profits than entities operating in a competitive environment. The exercise of market power is implausible in the context of long-term procurement because the IOUs have many procurement alternatives. They can buy under long-term contracts, they can buy on the spot market, and they can self-generate (using existing facilities), and even build their own generation capacity. As such, no single supplier or group of suppliers can effectively force IOUs to purchase at prices that exceed the costs of these alternatives.

There are no monopolies in generation in California or the wider Western Electricity Coordinating Council ("WECC") marketplace and the level of market participant concentration in California generation indicates that oligopolistic behavior, as described by classical economic theory, is not feasible either. Moreover, there is an extensive market monitoring regime in place that should detect and prevent any illegal abuses of market power. It is also not realistic to claim that market participants could successfully collude to manipulate the market, as the conditions for tacit collusion, which the IOUs' testimony repeatedly refers to, are not in place in the California landscape. Finally, the IOUs have not provided any evidence to date of any actual market power in practice, especially in regards to long-term procurements.

2.1 Market power

Market power is defined as the ability to profitably maintain prices above competitive levels for a significant, non-transitory period of time. Market power abuse reduces the efficiency of competitive markets. Market power can be exercised by one firm, i.e., monopolization, or by a number of firms acting in concert (collusion).

A monopoly is best described as market that has only one seller but many buyers. As the sole producer of a product, the monopolist is in a unique position: it can raise the price for its products or services without worrying about a competitor charging a lower price and thereby capturing a larger market share at the monopolist's expense. The monopolist in this case *is* the market and fully controls the amount of output for sale and the price at which it is sold. This, as we discuss in more detail in the sections below, is *not* the case in California where there are numerous buyers and numerous sellers of electricity.

A pure monopoly is rare. It is more common for a few firms to account for most or all production, which is considered an oligopoly. In oligopolistic markets, only a few firms compete with one another and entry by new firms is impeded, either through artificial barriers to entry or through pricing strategies by the incumbents known as limit pricing (where they set prices above competitive levels but below the level necessary to incite new entry). Over the long run, some or all of the firms earn substantial profits because of these barriers to entry. Again, as we will demonstrate in the next sections, this is *not* the case in California, where generators can easily enter and exit the market and have in fact done so over the last five years. In an oligopolistic market, a firm sets price or output depending in part on strategic considerations regarding the behavior of its competitors. Likewise, competitors will set their prices and outputs based on what the firm is doing. Oligopolistic firms often find themselves at a strategic cross-road, known as the *Prisoners' Dilemma*.[6] They must decide whether to compete aggressively (and thereby capture a larger market share at their competitors' expense) or to cooperate with their competitors (setting higher prices and limiting output). While there is an incentive to cooperate (i.e., higher profits for all competitors), only under certain conditions and payoffs can firms trust or expect their competitors to each limit output in order to achieve a higher market-clearing price.

2.2 Tacit collusion

Tacit collusion is a form of oligopolisitc behavior whereby a number of firms coordinate their production and pricing strategies so as to approximate the effects of a monopolist. As a result, the firms tacitly colluding will obtain prices above workably competitive levels. Tacit collusion typically refers to coordination achieved through "unspoken" pacts. Tacit collusion is possible when firms interact on a repeated basis, such that higher prices are achieved through an "unspoken" but well understood agreement among the firms to withhold some portion of each firm's product. Furthermore, tacit collusion is possible only if deviation by any single firm from the collusive path could be monitored and punished (i.e., deviation would trigger some retaliation by the remaining firms).[7]

According to the classic text on tacit collusion, the *Theory of Industrial Organization*, by Jean Tirole, there are three main conditions under which tacit collusion can be implemented:

- market participants must be able to see each other's prices, so as to appropriately detect and punish firms that undercut the other collaborators;
- all suppliers must have very similar cost structures; and
- there must be a high concentration of suppliers.

6 Under the classic example of "Prisoner's Dilemma" in a simple two-player "game" there is only one equilibrium – the players each individually choose not to cooperate. This is referred to as a Nash Equilibrium. A Nash Equilibrium exists if no player can benefit by changing his strategy while the other players keep their strategies unchanged. The concept of the Nash Equilibrium was developed by mathematician John Nash in 1951 and is one of the foundations of modern game theory.

7 In order to be sustainable, retaliation must be sufficiently likely and costly to outweigh the short-term benefits from "cheating" on the collusive path. These short-term benefits, as well as the magnitude and likelihood of retaliation, depend in turn on the characteristics of the industry.

Some industry experts have observed in some instances that high priced bids (for small quantities) have set the market-clearing price, and have questioned whether this is a sign of tacit collusion. In fact, this behavior – sometimes referred to as "hockey stick bidding" – is unlikely to be exercise of market power, especially in a market with many (relatively small) suppliers. Rather, such bidding may be a natural and efficient bidding process for relatively small suppliers to pursue in a competitive market in the face of high uncertainty and volatility of the market and given the fact that there are high fixed costs of power plant operation, which need to be recovered at some point through energy revenue streams.

With uncertainty about demand and competitors' supply in the market, small suppliers will structure their offers in a way such as to maximize their expected revenue potential and resolve risks and uncertainties. Individual suppliers will submit a diverse set of price and quantity offers – including some offers to sell small quantities at very high prices.[8] This type of pricing strategy is consistent with the efficient pricing rules put forth in the economic theory of the contestable markets, which builds upon the model of perfect competition by recognizing the existence of fixed costs. The theory states that firms, to cover their fixed costs, mark up their prices in inverse relation to the price elasticity of their own demand. Hockey stick bids, in this regard, provide an efficient means (since it only costs the firm a small fraction of its output) for small suppliers to contingently structure their offers to select those periods when demand for their services is inelastic, so that they can potentially recover large sunk or fixed costs over those very short, highly unpredictable periods of time.[9]

The presence of such pricing strategies in the spot market (and possibly in the offers submitted in response to Requests For Offers ("RFOs")) would thus suggest that small suppliers are under a lot of uncertainty. Their pricing structure reflects this uncertainty. Consistent with auction theory, this would then lead one to conclude that if buyers release information that allows the smaller suppliers to better understand the needs of the buyers over time and adequately position themselves to meet such demand, then the suppliers may no longer need to try to "hockey stick bid" for information gathering purposes. Rather, the suppliers' efforts may be refocused on competing against each other.

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8 This is also the "target" Dr. Plott refers to in his testimony.

9 A classic example of contestability comes from Baumol, Bailey and Willig, *Weak Invisible Hand Theorems on the Sustainability of Prices in a Multi-product Monopoly*, American Economic Review, 67: 350-65, 1977. They model a natural monopoly where firms can only set linear prices (that is, prices cannot vary with volume purchased). Free entry and exit result in supply by a single firm that earns no profit. Prices are set according to the Ramsey formula—they are marked up above marginal cost in proportion to consumers' demand elasticities so as to just recover the firm's costs.

3 Comparison of California in 2000-2001 and present day

The California energy crisis of 2000-2001, which resulted in extended periods of very high prices, rolling supply interruptions, and the bankruptcy of one IOU (PG&E), ultimately led to a second restructuring of the state's electricity sector. The crisis was a severe and traumatic experience for consumers, public officials, and energy companies alike. Based on hindsight, the crisis can be attributed to several factors: unprecedented "dry" hydrological conditions in the Western Interconnect, lack of a viable alternatives to spot purchases for the IOUs (restriction on forward market transactions outside the California Power Exchange), lack of market signals to retail and resulting inelastic demand, IOU obligation to supply under a fixed retail tariff, market rules and design that allowed for manipulation of congestion and enhanced generator market power, as well as slow progress of new plant construction. In this section, I compare the market environment, the market structure, and the regulatory framework in California in 2000-2001 and today to illustrate that the conditions prevalent during the 2000-2001 crisis no longer exist. First, however, I present a brief overview of California's deregulation process as context.

3.1 Brief overview of California's deregulation process before and after the 2000-2001 crisis

On March 31, 1998, California officially granted full retail and wholesale access to its electricity market as a result of Assembly Bill 1890, which was passed in 1996. The basic elements of the restructuring plan included:

- opening of the retail market: all customers are free to choose a competitive supplier and if no competitive supplier is chosen, default supply provided by incumbent utility;
- a 10% reduction in the price of electricity through March 31, 2002;
- recovery of stranded costs through a competitive transition charge ("CTC") through December 31, 2002;
- creation of an independent CAISO and a centralized power exchange (the California Power Exchange, or "Cal-PX") through which IOUs had to transact;
- divestiture of at least 50% of fossil fuel fired plants by PG&E and Southern California Edison ("SCE") to nine new participants.

A variety of different solutions were launched in response to the energy crisis of 2000-2001. After taking a series of preliminary steps to address the crisis, such as halting the direct access program and having DWR step into to be the counterparty for long-term contracts, the regulatory authorities launched an overhaul of the market structure. The broadest of these major initiatives was the California ISO Market Design 2002 ("MD02"), which was introduced in January 2002 and the first phase of which was implemented in October 2002. MD02 introduced a zonal-based pricing regime with a real-time balancing market similar to the structure found in ERCOT. Supply resources are paid at the zonal prices. Load buys at the average zonal price in the "load aggregation zone" in which it is located. Currently, there are 16 load aggregation zones in CAISO. The CAISO also runs an ancillary services market and a congestion market. The Cal-PX, which went bankrupt during the energy crisis, has not been replaced and all day-ahead transactions occur in the bilateral market.

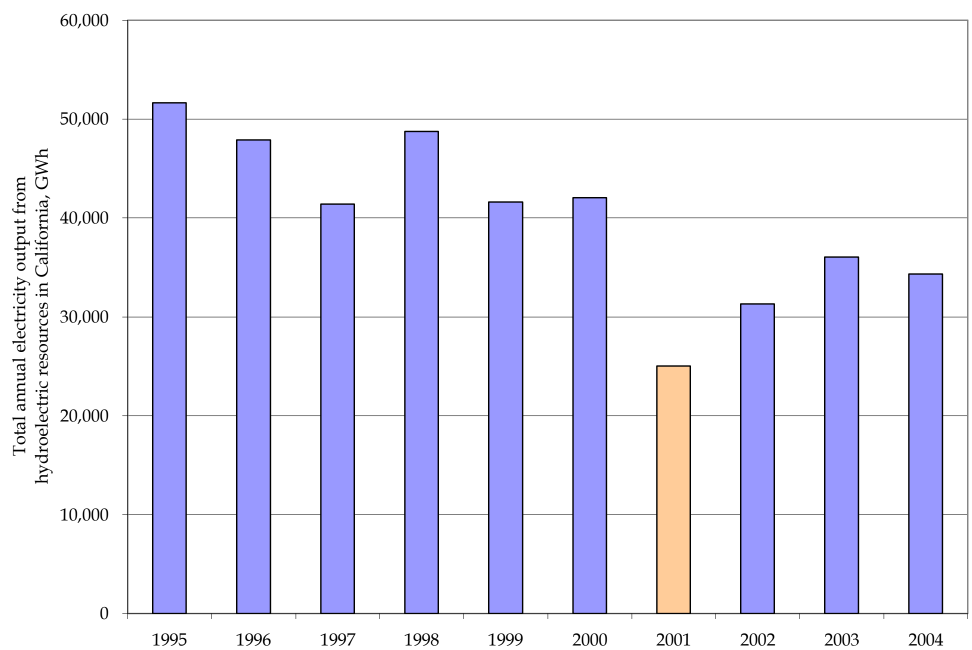
3.2 Market environment

There are three key areas in which the market environment in 2000-2001 and the current one differ. These are the level of hydroelectric production, which was unusually low in 2000-2001 as compared to historical levels, the amount of new generation built in response to increased demand, and the number of market participants and level of market concentration. I discuss each below, comparing the status of each during 2000-2001 to today to illustrate how different the market environment is today from what it was in 2000-2001 and why it is unlikely that a confluence of these three conditions could occur in the future.

3.2.1 Hydrology conditions

California produces and consumes a significant amount of hydroelectric electricity. In 2004, 16.5% of all electricity consumed in California was from hydroelectric resources; 12.5% of electricity consumed was generated from hydroelectric generating assets within the state and the remainder was imported from neighboring regions, mainly the Pacific Northwest.[10] Since only a small proportion of this electricity comes from pumped storage facilities,[11] the amount of power available to California varies greatly due to weather conditions.

Figure 1. Historical hydroelectric production in the state of California, 1995-2004



Source: California Energy Commission ("CEC")

10 Based on CEC statistics, available at http://www.energy.ca.gov/electricity/gross_system_power.html.

11 Of the approximately 12,500 MW of hydroelectric capacity in the state of California, only 2,633 MW is classified as pumped storage facilities according to the 2004 CEC power plant database.

The poor hydrology conditions that existed during the May 2000-May 2001 period were an deviation from the norm. Indeed, a historical assessment of regional hydro-electric production indicates that the 2000-2001 winter period resulted in the lowest hydroelectric production in a ten-year period. In California, hydroelectric production was almost halved in 2001 to about 25,000 GWh, as compared with an average of 45,000 GWh the six years prior. Since then, hydroelectric production has been lower than the historical average but still above 30,000 GWh per year. California's historical hydroelectric production is shown in the graphic above. In the Pacific Northwest, the crisis in hydrology output started in 2000, with total annual electricity output from hydroelectric resources at less than 40,000 GWh as compared to a historical average of close to 70,000 GWh.[12] Thus, it is clear that the hydrology conditions which occurred in 2000-2001 were indeed abnormal and not indicative of normal seasonal patterns.

3.2.2 New generation additions

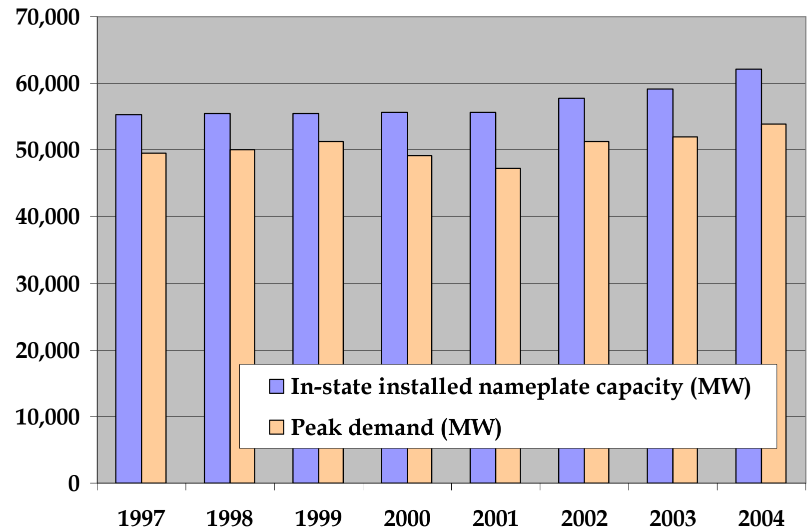
A major component of the 2000-2001 energy crisis was the fact that the state of California simply did not have sufficient generation capacity in state to meet its demand. This was exacerbated by the fact that California's demand had increased rapidly during the late 1990s. Peak demand in California increased by approximately 4,000 MW between 1996 and 1999,[13] whereas generation capacity in the state increased by only 778 MW during the 1996-2000 timeframe.[14] Most generators had halted large scale investment during the deregulation process due to uncertainty about how the market would develop. Thus, there were few new projects built in the 1990s. Stringent air quality standards further decreased available capacity as some power plants were forced to shut down when they reached their emissions limits. This trend in low levels of additional generation capacity is shown in the graphic below which shows that installed capacity in the state stayed around 55,000 MW from 1997 through 2001.

12 Based on Energy Information Agency ("EIA") statistics regarding annual total hydroelectric production in each state.

13 Statewide coincident peak load actually declined in 2000 and 2001 as a result of the crisis. See CEC, http://www.energy.ca.gov/electricity/index.html#demand.

14 Source: CEC. See http://www.energy.ca.gov/database/index.html#powerplants.

Figure 2. Comparison of supply-demand balance before and after the energy crisis



Source: Installed capacity data is from CEC 2004 database, I used the "on-line date" to place installed capacity in each year; peak demand data for 2001-2004 comes from annual CEC peak demand and supply assessment using 1-in-2 peak demand; peak demand data for 1997-2000 comes from the CEC coincident historical peak demand assessment.

The amount of installed capacity in California increased after the energy crisis in response to the clear need for new generation as well as to the introduction of an expedited siting approval process. Indeed, in 2001, more than 2,000 MW were brought on-line; in 2002, approximately 1,300 MW were brought online; and in 2003, more than 3,000 MW of new capacity was brought on line.[15] The impact of demand-side management programs, which I address in Section 3.4.3, can also be observed in this graphic. Demand actually decreased in 2000 and 2001 as a short-term response to the crisis.

3.2.3 Number of market participants

Another difference in California today as compared to the 2000-2001 period is the level of market concentration in generation. While many of the former utilities and Independent Power Producers ("IPPs") that owned most of the capacity in the 2000-2001 are still heavily invested in the California market, the addition of new generation capacity and introduction of new entities has diluted the incumbents' market concentration. This is illustrated in two ways. First, using accepted regulatory measures for market power potential, our analysis reveals that the California state market is not a concentrated one and its concentration has *decreased* since 2000. The Herfindahl-Hirshmann Index ("HHI")[16] for the California state market was approximately

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15 Based on information from the CEC's 2004 power plant database.

16 The Herfindahl-Hirschman Index ("HHI") is a measure of the concentration of supply in a defined market, based on a sum of the square of the individual suppliers' market shares. The HHI was developed on the basis of Cournot market theory in economics and has been implemented as the standard tool in horizontal market power analysis by the Department of Justice ("DoJ") and the Federal Trade Commission. The DoJ's *Merger Guidelines* lay out three ranges of market power concentration: an un-concentrated market is

470 in 2000 and is now estimated at 388.[17] The decrease in the HHI of almost 100 points from 2000 to 2004 indicates that the market concentration of the market has decreased significantly during that time. Moreover, an HHI below 1,000 indicates an *un-concentrated* market. A list of the top ten capacity owners and their respective market share in the California market reveals that while many of the top ten are the same, many have seen their market share decrease by about 1% on average, as shown in Figure 3.[18]

These new participants also contribute to the diversity and competitiveness of the market. In addition, transmission additions and enhancements have also helped to further de-congest the transmission in the state and enable more imports, further increasing competitive pressures in the state. As such, it would be difficult to claim that the potential for market power abuse exists in California today.

Figure 3. Comparison of generation capacity ownership in California in 2000 and 2004

Rank	Company	2000 Installed capacity (MW)	Market share (%)	Company	2004 Installed capacity (MW)	Market share (%)
1	PG&E	6,578	12.1%	PG&E	6,312	10.2%
2	LADWP	4,857	8.9%	LADWP	5,274	8.5%
3	AES	4,145	7.6%	Duke	4,437	7.1%
4	Reliant	3,906	7.2%	Reliant	3,602	5.8%
5	SCE	3,438	6.3%	SCE	4,467	7.2%
6	Mirant	3,077	5.6%	Mirant	2,366	3.8%
7	Duke	2,597	4.8%	AES	4,284	6.9%
8	Calpine	1,936	3.5%	Calpine	1,913	3.1%
9	USBR	1,882	3.4%	USBR	1,908	3.1%
10	CDWR	1,590	2.9%	SMUD	1,357	2.2%
	TOTAL	**54,573**		**TOTAL**	**62,181**	

Source: Based on CEC's 2004 power plant database for 2004 figures; EIA's 2000 Inventory of Utility and Non-Utility Electric Power Plants (published January 2003) was used to determine the above figures for 2000. Note that I am using data for the entire state of California, not just CAISO.

indicated by an HHI below 1,000; a moderately concentrated market is indicated by an HHI ranging from 1,000 to 1,800; and, a highly concentrated market is identified by an HHI above 1,800.

17 I calculated the HHI for the California market using CEC's 2004 power plant database. For our 2000 calculations, I removed all plants that came on-line after 2000 and used the EIA 2000 *Inventory of Utility and Non-Utility Electric Power Plants* (published in January 2003) to adjust for assets that were purchased/sold between 2000-2004. Note that I am using data for the entire state of California, not just CAISO.

18 The analysis of market shares for capacity owners was also based on CEC's 2004 power plant database for the 2004 data. For 2000, I relied on the EIA's 2000 *Inventory of Utility and Non-Utility Electric Power Plants* (published in January 2003). Note that I am using data for the entire state of California, not just CAISO.

3.3 Market structure

The California market structure also changed substantially between 2000 and 2004. The main difference is due to the fact that most activity occurred in a centralized spot and real-time imbalance market in 2000, whereas most activity today occurs in bilateral forward markets. I compare the nature of the spot and forward markets in the two timeframes in the subsections below. First, however, I provide some context for the general market structures in place during the 2000-2001 period as compared to today's market structure.

Under the original market design in place in 2000, the operation of the Cal-PX was separate from the CAISO. Two distinct non-profit corporations were created to prevent the CAISO from influencing financial outcomes on the exchange by favoring one supplier over another in scheduling and dispatch. The CAISO was designed to act as a regional system operator with the goal of ensuring reliability, while the Cal-PX's mission was to provide an efficient, competitive energy auction to all suppliers and buyers. The Cal-PX managed a day-ahead and hour ahead market and hourly prices were openly published on the Cal-PX website, providing for a high level of transparency on willingness to pay in real-time to all participants.

With the dissolution of the Cal-PX in 2001 and the general market paradigm at that time, the entire market design was deemed inadequate and overhauled. Emerging out of the MD02 process was a real-time balancing market managed by the CAISO which is effectively a zonal pricing system. There is no longer a centralized day-ahead market; rather, most day-ahead activity is in the bilateral market. There is also a liquid bilateral market for forward physical and financial transactions. In addition, the CAISO also runs a real-time market for ancillary services, congestion, and imbalance energy.

3.3.1 Spot market

As part of the deregulation process, all of the state's IOUs were obliged to sell and to purchase most of their power in the Cal-PX during a transition period which was due to run through March 2002.[19] Other market participants, such as municipal utilities and IPPs, were exempt from this requirement and could use Cal-PX or transact on a bilateral basis. Moreover, the IOUs were required to sell all of their remaining owned generation through the Cal-PX under pre-reform long-term contracts based on the fuel source of the generation.

The Cal-PX determined an unconstrained market clearing price for every hour. This schedule was then submitted to the CAISO, which adjusted the schedule to account for congestion. Cal-PX then determined the zonal marginal clearing price to arrive at a final schedule for all participants. There was no restriction or cap on the energy market price as there was in the aftermath of the crisis (soft price caps were instituted in 2001). A key characteristic of the 2000-2001 electricity market was the high percentage of electricity procured through the spot market.[20] During the years of its operation, volume on the Cal-PX represented 80%-90% of all

19 Referred to as the "Buy-sell Requirement" under CPUC's Decision 9512063.

20 While the Block Forward Market ("BFM") was established on Cal-PX in November 1999, the IOUs were only allowed to purchase a limited amount of these products (one-third of their historical load) until March 2000, when they were allowed to purchase their entire net short position on the BFM. However, the recovery of

energy scheduled by CAISO.[21] In 2000, IOUs procured 60% of their required supply through the short-term market.[22]

An additional characteristic of the 2000-2001 spot market was the fact that arbitrage opportunities existed between the Cal-PX day and hour ahead markets and the CAISO real-time balancing market, which ultimately enabled a certain level of market manipulation. Cal-PX ran two markets – a day-ahead market and a day-of market. Both markets functioned similarly except that the day-of market was oriented around three auctions for specific time frames of the day, allowing market participants to adjust for deviations in their actual load. Note that this day-of market operated by Cal-PX was distinct from the real-time balancing market run by CAISO, which was geared at balancing the grid for reliability purposes in a real-time manner. While one would expect that the prices on these markets, which were interlinked, to converge to an equal or very similar level, certain complexities and restrictions on the functioning of these markets meant that arbitrage opportunities existed. As a result, during the 2000-2001 period, purchases in the Cal-PX day-of market averaged 20% to 30% of total volume, which is substantially higher than the average relative volume (in the range of 5%) transacted in other real-time markets across North America. Some industry experts have argued that this high level of real-time market activity partially contributed to the high price levels and high volatility seen on the California market during 2000-2001.

After the bankruptcy of Cal-PX and the implementation of MD02, the concept of a centralized spot market for day-ahead transactions disappeared in California. The day-ahead marketplace is purely geared off bilateral transactions. The liquidity of day-ahead trading has diminished dramatically as utilities are no longer required to purchase spot, and are, in fact, encouraged to procure on a more long-term basis. Indeed, in the recent procurement plans submitted by the utilities to the CEC, plans for short-term spot procurement for the 2009-2016 period indicated that on average, the utilities planned to procure less than 5% of their supply needs from the short-term market.[23] Moreover, the arbitrage opportunities between the day-ahead market and the real-time (balancing energy) market no longer exist and now real-time procurement is at a volume consistent with other markets across the US.[24]

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costs for these products was subject to the Post-Transition Rate-making Process, and not allowed on an ex ante basis. (See http://www.cpuc.ca.gov/word_pdf/REPORT/3561.pdf)

21 Byrne, John, Young-Doo Wang, and Yung-Min Yu, "Lessons from a Comparative Analysis of California and PJM Electricity Restructuring Models," Center for Energy and Environmental Policy, University of Delaware, June 2005.

22 Id.

23 I used Tables 11, 23, and 35 of the CEC Staff Paper, *Resource Plan Aggregated Data Results*, June 2005 (CEC 150-2005-001) to develop this estimate. I averaged data from years when the utility was planning to buy from the spot market. Note that there were differences among the utilities: PG&E's average short-term procurement was 2.8%; SCE's was 0.6%; and, SDG&E's was 7.6%.

24 In 2004, 5,190 GWh of real-time electricity were traded on CAISO as compared to the 239,769 GWh that were consumed that year (based on CAISO *2004 Annual Report*).

3.3.2 Forward market

The forward market was a fairly illiquid one in the 2000-2001 period, due to regulatory restrictions on forward market transacting by the agents for the majority of in-state load (e.g., the IOUs). (I discuss the restrictions in Section 3.4.1.) In 2000, estimates show that IOUs procured 6% of their energy needs through longer term contracting (i.e., QFs and other "grandfathered" commitments), as opposed to 34% from their own generation and 60% from the spot market.[25]

Following the crisis, the effective barriers to forward transacting were eliminated, resulting in increased liquidity in forward markets in California. There is currently no centralized forward market. Forward transactions are traded on a bilateral basis over a variety of timeframes ranging from shorter term (one month) to long term (five to ten years), with price indications provided by a variety of third-party vendors.[26] Volumes on the forward market continue to increase. Forward transacting for hedging purposes has become increasingly important in the California market, as generally occurs in more sophisticated markets.[27] For example, in 2004, financial trading of SP-15 derivative products was double that of the physical volume.[28]

In addition, the forward market is a highly fragmented one, with a plethora of potential counterparties. For example, I analyzed the California IOUs' contractual counterparties for the first quarter of 2005, as reported to FERC in Electric Quarterly Reports ("EQR"), and determined that the utilities had more than ten counterparties in that quarter for both short and long-term contracts.[29]

3.4 Regulatory framework

There are four major developments on the regulatory front that differentiate California's electricity market in the 2000-2001 period from today: (1) the removal of restrictions on forward transactions, (2) the removal of the disconnect between energy prices and the retail tariff, (3) which in turn has made load more sensitive to peak conditions, and (4) improvement in the market power monitoring and mitigation regulations. I discuss each in more detail below.

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25 Byrne, John, Young-Doo Wang, and Yung-Min Yu, *Lessons from a Comparative Analysis of California and PJM Electricity Restructuring Models*, Center for Energy and Environmental Policy, University of Delaware, June 2005.

26 I provide information on these data vendors in Attachment F entitled, *Availability of market price information for wholesale electricity markets in the Western Electricity Coordinating Council (WECC).*

27 As stated on page 71 of FERC's *2004 State of the Markets Report*, "The increase in trading of NP15 and SP15 financial products is consistent with general trends in electricity trading as non traditional electricity trading entities (hedge funds and banks) have become active in these financial markets, and as industry credit has improved."

28 FERC, *2004 State of the Markets Report*.

29 More information on this subject matter is provided in Attachment E entitled, *Guide to FERC Electric Quarterly Reports: Availability of Specific Contract and Transaction Data*.

3.4.1 Restrictions on forward market transacting

The original deregulation process imposed restrictions on the utilities to enter into forward contracts as a backlash to the high out-of-market costs incurred by the IOUs in preceding years with Qualifying Facilities ("QF") and Non Utility Generators ("NUG") arrangements. The positive features of forward contracts were not sufficiently emphasized during restructuring. For example, forward contracts reduce exposure to spot market price risk to buyers; they provide incentives for sellers to bid into the market to cover their contract obligations; and, they also serve as a catalyst for new investment by providing a viable basis for project financing.

The utilities had already, as per regulatory requirements, sold a majority of their generation capacity. In addition, they were required to buy and sell most of their generation on the Cal-PX in order to create a liquid spot market. During this period, California's utilities' forward contracting opportunities were limited to the Cal-PX's Block Forward Market, which enabled buyers to purchase a limited amount of power (in 1 MW or 20 MW "blocks") for up to nine months in advance. These contracts, however, were unattractive to the utilities because the permitted purchase quantities were small and the contracts applied only to specified peak periods, limiting the utilities' ability to match their load shape. Moreover, the utilities were effectively limited to the Cal-PX's products (rather than bilateral products) because of cost recovery uncertainty.

In August 2000, the California Public Utility Commission ("CPUC") relaxed its restrictions on bilateral contracts and allowed the utilities to enter into long-term contracts with generators to hedge against price spikes. The Department of Water Resources ("DWR") ultimately took over much of this long-term procurement during the period of financial crisis for the utilities. Starting in the beginning of 2003, IOUs were again allowed to enter into long-term contracts. Now they procure a large part of their load via long-term procurement. Contracts usually last up to about five years, although terms of up to ten years are allowed. Many of the long-term contracts are procured via a competitive auction or Request for Offers ("RFO") process. In addition to forward contracting, utilities can also use their own resources, build their own resources, and buy from the spot market, thus giving them much more flexibility than they had during the 2000-2001 era for meeting the needs of their customers.

3.4.2 Procuring on the open market and selling under a fixed retail rate

As part of the original deregulation process, the entire retail market was opened to competition; however, the incumbents were required to continue to provide default service to those who did not choose alternative suppliers. Until the utilities' stranded costs were recovered, default supply was to be provided under a 10% rate reduction. This means that the cap on retail tariffs effectively de-linked retail prices from the actual costs of electricity supply. It was this disconnect that resulted in the severe financial difficulties of the IOUs and the ultimate bankruptcy of PG&E, as I describe in more detail below.

SCE and PG&E were operating under a rate freeze in 2000-2001[30], which meant that they were not allowed to pass the full cost of wholesale power onto their customers. As wholesale prices rose, SCE's and PG&E's financial losses began to mount and credit problems ensued. Marketers began to question the two IOUs' ability to pay for power and consequently opted to send their production elsewhere, reducing the liquidity of the Cal-PX. PG&E ultimately filed for bankruptcy as a result of the losses incurred during this period and has now emerged out from Chapter 11. SCE opted to raise funds to meets its financial obligations through the sale of its transmission assets.

An illustration of the disconnect between capped retail tariffs and the wholesale price in the market is provided in Figure 4 on the next page. The retail tariff caps in the table include generation, transmission, and distribution rates, as well as other charges. Transmission and distribution comprised approximately 50% of an average residential customer rate. Thus, the generation component would be approximately half of the retail tariff cap noted above, i.e., approximately 5 cents/kWh in 2000 and 7 cents/kWh in 2001. It is this generation component that I compare to the average Cal-PX price for wholesale energy, which was over 10 cents/kWh on average in 2000 and was effectively capped at 15 cents/kWh for some time in 2001 after the dissolution of the Cal-PX.

The impact of this disconnect was exacerbated by the fact that few customers left default supply service. The utilities were required to serve customers that had not opted to switch to a competitive retailer under a fixed rate cap. Given that the fixed rate was lower than the market rate on average after 1999, virtually all customers stayed with their utility under the frozen rates. Only about 12% of load switched to competitive suppliers,[31] leaving the IOUs with a larger default supply load than initially expected. As a result, their net short positions, which had to be procured on the spot market, were also larger than expected during the market design phase.

Figure 4. Comparison of utility capped prices and average wholesale price (Cent/kWh)

	1999	2000	2001
PG&E retail tariff cap	10.26	10.27	13.27
SCE retail tariff cap	10.28	10.32	14.67
SDG&E retail tariff cap	10.31	13.7	14.51
Cal-PX average price	3.046	10.07	15.00*

Note that retail tariff caps include generation, transmission, distribution, and other charges; Cal-PX price refers only to generation

** Note that Cal-PX stopped trading at the end of January 2001; thus the figure in that data refers to the cap placed by FERC on California wholesale electricity sales ($150/MWh).*
Source: CEC

The problems created by this disconnect have been completely addressed in the restructuring of the California electricity market. Retail competition had been halted. Customers are currently

30 Note that SDG&E had recovered its stranded costs by this point and was able to pass its wholesale energy costs onto consumers.

31 Paul Joskow, *California's Electricity Crisis*, MIT, September 2001.

forbidden to leave their regulated utility's electric service until 2013, when the long-term contracts signed by the state during the energy crisis expire. Retail customers that switched before September 20, 2001 are allowed to stay with their competitive supplier. The rates for consumers that have not switched are no longer the capped retail rates of the 2000-2001 era. Rather, they are composed of costs associated with the long-term DWR contracts, the cost of utility retained generation, a DWR bond charge, public purpose program costs, and a transmission and distribution charge. Thus, the retail rates are no longer de-linked from the actual costs of energy supply.

3.4.3 Lack of market signals and inelastic demand

Customers who remained on default supply service had no incentive to adjust their demand as their prices per unit of consumption remained fixed and at a level that was not reflective of wholesale market conditions. The lack of appropriate retail market price signals led to inelastic demand, which exacerbated the high prices in peak periods, as the utilities were not able to convince consumers to conserve energy.

This has now changed. Retail tariffs *do* change over time to reflect the embedded cost of electricity supply. Moreover, during the energy crisis and continuing through today, California put in place numerous mechanisms to encourage demand-side response to high power prices or to tight supply-demand conditions. Demand relief programs have been put in place as a precautionary measure against capacity shortages and allow the CAISO to call on individuals or groups to reduce energy consumption for a specified period of time. Participants in the demand relief program receive a fixed monthly payment. In addition, other programs providing incentives for customers to use localized distributed generation to provide some or all of the consumer's electricity have also been in place. This focus on demand-side management has helped to make consumer demand less inelastic during peak periods. Indeed, California is seen as one of the more sophisticated, innovative, and successful jurisdictions in promoting demand-side management.

3.4.4 Market power mitigation

Following the electricity crisis in 2000-2001 and numerous allegations of market manipulation and gaming, increased effort has been placed on the mitigation of potential market power and the detection of market power abuse. For example, the Market Analysis Department of the CAISO is charged with ensuring that a competitive market is viable in California. Some of their activities in this endeavor include the development and monitoring of structural market indices, the development of data requirements for market participants, investigation of gaming and other instances of market abuse, and reporting to FERC and other regulatory agencies. The Department of Market Analysis monitors the market and price outcomes to identify conditions different from what would be expected under normal competitive behavior. It also supports the Market Surveillance Committee ("MSC"), which consists of an independent group of industry experts that can suggest changes in rules or protocols or recommend sanctions or penalties directly to the CAISO Board of Governors (the "Board"). The MSC meets regularly and frequently issues opinions to the Board on ways to improve the competitiveness of the California electricity market.

4 Conclusions

In their testimony appealing the NOI, the IOUs claim that the release of the aggregated summary tables could lead to a repeat of the 2000-2001 energy crisis[32] and the potential manipulation of the energy market, thereby exposing the utilities and their customers to higher prices than those that would occur if the information were not released. I do not think this is a realistic or an accurate concern. First, it is very unlikely that an energy crisis like the one of 2000-2001 could occur again, as the most of the conditions leading up to that crisis (and prevalent during the crisis) have either been permanently dispelled or are highly unlikely to re-occur in combination Second, the prerequisite conditions for any classic abuse of market power, such as monopolization or collusion, do not exist in California today in a way that would affect the long-term market for which the NOI data release is relevant. In contrast to the IOUs' appeals, economic theory would suggest that the aggregated summary tables would have a completely different effect – it should lead to an improved level of market transparency, reduced uncertainty, and more focused participation by various suppliers, which in combination should result in increased competition in the California electricity market.

4.1 History is unlikely to be repeated: crisis of 2000-2001

California's market environment has changed, making a repeat of the events of 2000-2001 unlikely. Though dry hydroelectric conditions could occur sometime in the future, their impact would be moderated by the addition of new fossil-fuel fired generation and new demand-side management programs. Moreover, the increase of capacity in the state and the entry of new participants have diluted supply-side concentration.

The market structure in California has also changed significantly since the power crisis in 2000-2001. Instead of having most transactions occur on a centralized spot market, the bulk of procurement now occurs in a bilateral market. While price indices for forward bilateral transactions and detailed historical transaction data are available, a market-wide spot price is no longer available in real-time. Moreover, the institutional incentives to reserve capacity to bid into the real-time market have also been removed.

Regulatory initiatives are also no longer binding on the IOUs' ability to procure from alternative sources. The IOUs have many options for long-term procurement, including self-supply using existing resources and investment in new generation. Indeed, one can credibly argue that the IOUs should be able to frustrate any uncompetitive behavior by existing suppliers through the alternative of utility investment. Additional market power mitigation mechanisms have also been put in place since 2001 to deter and detect any potential abusive behavior.

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32 Indeed, among the myriad explanations for why the energy crisis occurred, the availability of detailed price, supply, and demand data have never been mentioned as a likely cause. In fact, less – not more – planning data was publicly available following deregulation. Indeed, it was a direct result of the California electricity crisis that the FERC mandated the Electric Quarterly Report (EQR) system to improve information transparency and reliability. (For more information on the FERC EQR system, please see Attachment E entitled, *Guide to FERC Electric Quarterly Reports: Availability of specific contract and transaction data*).

4.2 IOUs' concerns about potential market manipulation are unfounded

There are three distinct reasons why the IOUs' concerns about market manipulation are unfounded. First, there is no single actor in the California market that can exercise sufficient market power to manipulate prices on a unilateral basis. This is evidenced by the fact that the largest actor in California, PG&E, has only 10% of installed capacity, prior to taking into consideration its substantial native load obligations.[33] Actual data on transactions filed with FERC also confirms that there is no single supplier serving the majority of the needs of each of the IOUs.

Thus, the IOUs' concerns about market manipulation and market power basically rest on an assumption of coordinated strategic behavior between the numerous energy suppliers, i.e., tacit collusion in the procurement processes of the IOUs. This brings me to the second reason why the IOUs concerns about market manipulation are unfounded: the conditions necessary for tacit collusion to be possible in the electricity supply sector in California do not exist under the current market structure, market environment, and regulatory framework. For example, the fact that utilities no longer are obliged to purchase from a centralized exchange and can, in conjunction with other approaches, purchase from a bilateral market, makes enforcement of the tacit goal very difficult, if not impossible. In addition, under federal guidelines regarding horizontal market power, the California market (on a state-wide basis) would be classified as an un-concentrated market, with a Hirschman-Herfindahl Index of less than 400. Generators in California continue to have diverse cost structures. Moreover, the additional market power surveillance mechanisms that have been implemented by CAISO will also help to prevent market power abuses. In the aggregate, the present environment makes tacit collusion generally untenable.

Figure 5. Conditions for tacit collusion in California today

Conditions for tacit collusion	Current status in CA	Tacit collusion possible?
Suppliers must be able to see one another's prices	Exact terms of contracts between the IOUs and their suppliers remain confidential; the market structure no longer encourages participants to wait to bid into the real time balancing market	no
Suppliers must have very similar cost structures	The owners of generation capacity in CA own diverse portfolios of generation assets (in terms of age, fuel, and general performance), which means their cost structures necessarily differ	no
There must be a high concentration of suppliers	Market has an HHI of 385 and more than 12 entities own more than 1,000 MW of aggregated capacity in CA	no

33 Based on CEC's 2004 power plant database.

Third, as I stated in the introduction to this document, the utilities have confused the timeframe for market manipulation with the timeframe of the aggregated summary tables. The IOUs' testimony implies concerns over the short-term market. For example, PG&E's witness, Roy Kuga claims that the aggregated summary tables "could seriously disadvantage and damage PG&E and its customers during our procurement of electricity over the next several years."[34] However, the aggregated summary tables that are intended for release[35] contain information about supply-demand from 2009 and onward, and thus refer to the IOUs' long-term procurement processes, rather than short-term transactions or spot market purchases. The IOUs' demand for energy in the long-term is elastic because of the various substitutes available to the IOUs today in terms of procurement strategies, methods, and potential counterparties. The elasticity of demand in terms of long-term procurement effectively negates monopolization, tacit collusion and other forms of market power exercise for the longer term horizon consistent with the time dimension of the aggregated summary tables.

4.3 Information release in NOI will only improve competitive forces in California's long-term market for energy

Not only will the release of the aggregated data under the NOI *not* lead to a repeat of the 2000-2001 crisis and *not* cause market manipulation in the long-term procurement processes, the information release is likely to improve competitive forces at work in the California market. The release of the aggregated data tables is expected to improve transparency for all market participants and level the playing field[36] for competition, as well as motivate potential new development, which will only further increase the competitive pressures on existing suppliers. The economic theory underpinning such an outcome is explained in my original testimony and further described in Attachment B, entitled *IOU long-term procurement, RFOs, auction theory and information release policy*.

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34 *See* Kuga at 1.

35 The design of the aggregated summary tables has purposefully taken into account the short-term inelasticity of demand in the face of a static group of suppliers over that timeframe. The three-year confidentiality window is supposed to match the timeframe for the development of new supply. Though baseload Combined Cycle Gas Turbine ("CCGT") development is more likely to be a four year endeavor from the initiation of application preparation to operation (for CEC-jurisdictional projects over the 1997-2005 period, the time to commissioning has averaged four years and two months), there are over 7,000 MW of already permitted development sites currently available (http://www.energy.ca.gov/sitingcases/all_projects.html); thus, development of such projects may take less time, (i.e. time for construction and commissioning). In addition, smaller sized plants and peakers are likely to have shorter construction lead times and possibly shorter permitting timeframes.

36 With the release of the aggregated summary tables, the smaller suppliers competing in the procurement process will feel more certain about long-term supply and demand dynamics. They will feel that this information will put them at equal footing with the more sophisticated participants. This additional certainty will reduce their timidness in the RFO process, further enhancing competition, and by definition, resulting in lower prices for the benefit of ratepayers.

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Attachment B

IOU Long Term Procurement, RFOs,
***Auction Theory and Information Release Policy*, Prepared By Julia Frayer, London Economics.**

IOU long-term procurement, RFOs, auction theory and information release policy

prepared by London Economics International LLC for the California Electricity Commission

August 12, 2005

1 Introduction

The California Investor Owned Utilities ("IOUs") do not want the California Energy Commission ("CEC") to release aggregated summary tables because they believe that this "confidential data" will lead to higher prices in their procurement process, and thus burden ratepayers with higher costs for electricity. The arguments raised by the IOUs rely on a belief that suppliers will be able to manipulate the information and collectively raise prices. As a result, the IOUs claim that the information proposed for release by the Executive Director's June 3, 2005 Notice of Intent ("NOI") is confidential and proprietary. However, in making this claim, the IOUs disregard crucial information about the Requests for Offer ("RFO") process. For example, Roy Kuga, witness for Pacific Gas & Electric Company ("PG&E"), claims that RFOs, which the IOUs issue in order to competitively procure energy for the longer term, already provide similar information on the IOUs' future needs, including "the type of resources needed and the timing of needs."[1]

While it is true that the RFOs provide a certain amount of information, this does not reduce the benefits to ratepayers from releasing he aggregated summary tables, given the realities of the procurement process and the California market for electricity. Moreover, in the context of all the similar, if not identical, information already readily available and in the public domain, the aggregated summary tables were designed to explicitly withhold information about supply-demand over the short term. In order to achieve the best outcome for ratepayers, it is necessary to "level the playing field" between the most sophisticated suppliers who can develop and analyze the detailed information already available to the public, and other potential suppliers that have less experience, or that are less analytically sophisticated. Of course no supplier, even those with very sophisticated capabilities, wants to waste resources on data analysis - the release of the aggregated summary tables can inform the decision as to what resources to devote to a potential project, encouraging both large firms and smaller firms to commit the necessary resources to respond to an RFO or begin developing a generation project. The aggregated summary tables - if distributed publicly - will go a long way to resolving at least some aspect of the uncertainty that all suppliers face.

Moreover, the release of the aggregated planning tables will let suppliers and potential new suppliers initiate their plans earlier. As a result, they will be better prepared when an RFO is

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1 *See* Kuga at 1-2.

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announced. As Dr. Michael Jaske points out in his testimony, other utilities actually believe that releasing this type of information is beneficial for a successful procurement process. For example, on page 3 of Attachment C entitled *The Myth of California IOU Uniqueness*, Dr. Jaske notes that "APS, Northwestern, PacifiCorp, PGE, PSE and Sierra Pacific all provide load forecasts and resource plans at least as detailed as the CEC Executive Director's aggregation proposal."[2] In the case of Arizona Public Service ("APS"), for example, it is noteworthy that supply-demand data on net shorts was an attachment to their long term capacity RFO. In other words, APS deliberately took steps to disclose this information in their RFO. To avoid short-term issues of balance and market power abuse, they supply demand data from 2007.

Auction theory, which is clearly applicable to the RFO environment under which IOUs procure long-term energy in California, suggests that the release of the aggregate summary tables would be beneficial, rather than harmful, as the information in the aggregated summary tables would substitute for the existing knowledgebase of the sophisticated suppliers and provide dependable information on the IOUs' future needs to the less sophisticated suppliers. The less sophisticated suppliers, armed with the same information as the sophisticated suppliers, are likely to be more certain in the value of the energy they are offering to sell and how others value this energy, which will allow them to be more aggressive in the competitive bidding process. Even for sophisticated bidders, the aggregate summary tables would provide context, and would show the proportional mix of loading order, generation, and transmission options, supplanting any privately developed projections on these matters. In addition, the aggregated summary tables would stimulate an expansion of the universe of suppliers by signaling the need for new capacity and allowing potential new suppliers to better prepare for a future RFO.

In this paper, I provide an overview of energy procurement policies in California, and summarize RFOs held recently by the IOUs. I place the evidence provided by the RFO processes in the context of auction theory, which clearly suggests that an information release that "levels the playing field" would lead to more efficient outcomes. Lastly, I offer the experiences of the Australian National Energy Market in this regard as further demonstration of the success of the practical application of this aspect of auction theory.

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[2] *See* Attachment C, *The myth of California IOU uniqueness*, prepared by Dr. Michael Jaske, Energy Commission staff.

2 Overview of the California IOUs' procurement processes

Under the California Public Utility Commission's ("CPUC") April 1, 2004 Order in R. 04-04-003 adopting the California IOUs' resource plans, the IOUs received permission to procure supply on a rolling 10-year basis. That decision was augmented and supplanted by D. 04-12-048 issued on December 20, 2004. The IOUs maintain ten-year period procurement plans that are reviewed every two years and revised if necessary. The IOUs are authorized to procure supply using short-term, medium-term, and long-term contracts, contingent on completing the required compliance filings. Contracts with terms of five or more years must be pre-approved by the CPUC.[3]

The CPUC has authorized the IOUs to procure supplies of the following products.

Figure 1. Products authorized for procurement by IOUs[4]

Ancillary Services	Gas Purchases (monthly, multi-month, annual block)	Tolling Agreement
Capacity (demand side)	Gas Storage	Counterparty Sleeves
Capacity (purchase or sale)	Gas Transportation Transaction	Emissions Credits futures or forwards
Electricity Transmission Products	Insurance (Counterparty credit insurance, cross commodity hedges)	Forecast Insurance
Financial call (or put) option	On-site energy or capacity (self-generation on customer side of the meter)	FTR Locational Swaps
Financial swap	Peak for off-peak exchange	Gas Purchases (daily)
Forward Energy (demand side)	Physical call (or put) option	Non-FTR Locational Swaps
Forward Energy (purchase or sale)	Real-time (purchase or sale)	Structured Transactions
Forward Spot (Day-Ahead & Hour-ahead) purchase, sale, or exchange	Seasonal exchange	Weather triggered options

The CPUC has authorized the IOUs to make use of a number of procurement methods, including centralized broker exchanges, real-time spot purchases from the California

3 Public Utilities Commission of The State of California, "Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning"; Rulemaking 04-04-003; April 1, 2004.

4 *See* D. 04-12-04 in Rulemaking 04-04-003, *Opinion Adopting Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company's Long-Term Procurement Plans*; December 20, 2004. Available at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/43224.htm.

Independent System Operator ("CAISO"), bilateral contracts and competitive solicitations (i.e. RFOs). The figure below summarizes all the authorized methods.

Figure 2. Procurement methods authorized for use by IOUs[5]

Competitive Solicitations (Requests for Offers)	Transparent exchanges, such as Bloomberg and Intercontinental Exchange	Short-term transactions of less than 90 days duration and with delivery beginning less than 90 days forward.
Direct bilateral contracting with counterparties for short-term products (i.e., less than 90 days)	Utility ownership of generation (interim rules set in D.04-01-50)	Longer-term non-standard products provided that the IOU include a product justification in quarterly compliance filings
Inter-Utility Exchanges	Open Access Same-Time Information Systems (OASIS)	Standard products in cases where there are 5 or fewer counterparties (for gas storage and pipeline capacity, only
ISO markets: Imbalance Energy, Hour Ahead, and Day Ahead (when operational)	Negotiated bilateral contracting allowed for	Transparent exchanges to include voice and on-line brokers

In a clarification, the CPUC authorized IOUs to procure supply using bilateral negotiations for agreements of up to three calendar months.[6] For transactions longer than one quarter, each IOU must consult its Peer Review Group ("PRG").[7] Indeed, Section VIII of the December 20, 2004 decision in R. 04-04-003 (D. 04-12-048), states that "[n]egotiated bilaterals are discouraged" for long-term planning.[8] Additionally, it should be noted that the IOUs have opted to use RFOs in their most recent longer-term procurements.

2.1 Competitive solicitation and RFOs

RFOs are a process by which a procurer solicits the submission of offers from outside parties who might wish to provide the required goods or services. Generally, an RFO will lay out a number of criteria that will be used to evaluate offers, usually technical criteria and asking

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5 *See* D. 04-12-04 in Rulemaking 04-04-003, *Opinion Adopting Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company's Long-Term Procurement Plans*; December 20, 2004. Available at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/43224.htm.

6 *See* CPUC Order D.03-12-062.

7 The Peer Review Group consists of non-financially interested stakeholders who review IOUs' submittals to the CPUC. The group assesses portfolio plans, bidding plans, and bid evaluation criteria for selecting third-party programs.

8 *See* Section VIII of D. 04-12-04 in Rulemaking 04-04-003, *Opinion Adopting Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company's Long-Term Procurement Plans*; December 20, 2004. Available at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/43224-07.htm#P761_187376.

price. Interested parties then submit their offers prior to a deadline. The offers are evaluated by the procurer, and winners are selected. In some variations, the initial submission stages are followed by the selection of a short-list. The short-listed firms then submit their final, binding, offers and enter into negotiations with the procurer about the precise terms. RFOs closely resemble a sealed-bid auction – the offers are essentially closed bids which are evaluated by the procurer, much as an auctioneer evaluates sealed envelope bids. To date, all the IOUs' recent RFOs have consisted of two stages with initial submissions by all potential bidders, followed by a "binding offer" stage from short-listed firms selected by the IOU.[9]

Economists have identified processes like RFOs and Requests for Proposals ("RFPs") as variations on the sealed bid auction because they similarly involve many bidders (many suppliers) competing to serve the needs of the buyer.[10] Indeed, the situation in California may be best characterized as consisting of many parallel auctions, since all three California IOUs have issued RFOs - thus competing against each other to secure the cheapest supply for their ratepayers.

2.2 Bilateral negotiations versus auction-like Requests for Offers

In his testimony on behalf of Southern California Edison ("SCE"), Dr. Charles Plott argues that the California market is best represented by multiple, pair-wise (i.e., bilateral) negotiations. This is possibly true in the short term, however, the IOUs' use of bilateral contracts is currently limited, as long-term bilateral agreements would require case-by-case review by the CPUC, and are generally discouraged as compared to "open and transparent competitive bidding processes."[11]

Longer-term transactions (which would parallel the time-frame of the aggregated summary tables) have recently been procured by the IOUs through RFOs. As well, at least one supplier has recently sold the output of its plants via an auction process.[12] As detailed in the previous

9 The two-stage variation generally has all the same characteristics of a single-round sealed-bid auction; though, the selection of a short-list (and potential for negotiations around non-conforming terms) may in fact predispose the design of this kind of auction mechanism to gaming due to the reduced number of participants. Sensible auction rules and care in the overall design of the RFOs could eliminate these concerns.

10 In his paper, *Auction Theory: A Guide to the Literature*, Paul Klemperer describes the sealed bid auction: "In the first price sealed bid auction each bidder independently submits a single bid, without seeing others' bids and the object is sold to [bought from] the bidder who makes the highest [lowest] bid." Likewise, in his paper *The Value of Information in a Sealed Bid Auction*, Paul Milgrom considers the sales of drilling rights by the US Department of the Interior, conducted by having interested parties submit offers for the right to drill particular properties, as a classic example of an auction mechanism.

11 *See* Section VIII of D. 04-12-04 in Rulemaking 04-04-003, *Opinion Adopting Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company's Long-Term Procurement Plans*; December 20, 2004. Available at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/43224-07.htm#P761_187376.

12 Duke Energy North America sold the capacity and energy of its Morro Bay Units 3 & 4 in an auction. PG&E was the winner.

section, RFOs are much better described as an auction process than a set of pair-wise negotiations. On that basis, economic theory on information policies for auction mechanisms is highly applicable to the situation facing the IOUs.

Dr. Plott himself says of markets that: "…it is well known from the study of insiders in open outcry markets that the information held by insiders quickly disseminates throughout the market and thus the effects of any asymmetries of information are typically small and hard to detect."[13] Open outcry markets are a well recognized type of open auction. Theories of the equivalence of different types of auctions tell us that the outcomes expected in an open auction are the same as those expected in a sealed bid auction. Moreover, theory recommends the release of all information that could strengthen competition in an auction setting. Thus, given that RFOs make the California market more like a series of auctions than pair-wise negotiations, we should conclude that the best policy on information would require the maximum disclosure. By extension, if Dr. Plott's experimental studies were set up in an auction-like environment, akin to RFOs, rather than pair-wise negotiations, we would naturally expect limited, if any, price impact from release of "asymmetric" information, given empirics from open outcry markets.

In addition to Dr. Plott's experiments being suspect from the perspective of applicability to real IOU power procurement practices, it is unclear whether the experimental study truly measures appropriately the impact of information disclosure in the current context. I find it curious that Dr. Plott fails to include a control group in his experimental analysis. In his experiment, Dr. Plott reports the results from sessions in which the sellers' have an informational advantage, and sessions in which the buyers have an informational advantage, but no sessions were run where neither sellers nor buyers have an advantage. It is standard for experimental studies in economics and other scientific disciplines to include a control group for purposes of baseline comparison. By leaving out a control group in the experiment's design, the average price impact that is reported in Dr. Plott's experimental study and testimony is probably biased – in other words, the noted price differences are likely overstating the importance of one-sided price revelation because they relate to observed average price differences in the experiment between sessions with informed sellers and informed buyers, not between informed sellers and uninformed buyers and sellers. Symmetry considerations would suggest that the difference between sessions with informed sellers and uninformed buyers and sellers would be less than what is reported in the study. It should also be noted that Dr. Plott's study tests the outcomes of a series of short, one-dimensional negotiations. Bilateral negotiations conducted in California (for example in the context of the final stages of the RFOs) tend to unfold over substantial periods of time and are conducted along many dimensions – price, time of delivery, length of term, termination rights to name a few – and are thus not highly similar to the style of negotiations used in the study.

13 *See* Attachment A to Plott's testimony, page 6.

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3 RFOs and Auction Theory

Since the start of 2004, seven RFOs have been issued by the California IOUs.[14] PG&E has issued four (two completed, two still in progress), SCE has issued two (both still open), and San Diego Gas & Electric Company ("SDG&E") has issued one (now completed). These RFOs are described in more detail below.

3.1 Pacific Gas & Electric RFOs

PG&E has issued four RFOs to date:

RFO	RFO Released	RFO Offers Due	RFO Concluded
2004 Renewables RFO (CLOSED)	July 15, 2004	August 23, 2004	December 2004
2004 Intermediate Term RFO (CLOSED)	September 8, 2004	September 29, 2004	January 31, 2005
2004 Long Term RFO - Power Purchase Alternative/ Facility Ownership Alternative	Originally issued November 2, 2004; suspended on January 7, 2005; reissued on March 18, 2005	April 27, 2005	Open
2005 Renewables RFO	August 4, 2005	September 15, 2005	Open

3.1.1 2004 Renewables RFO (closed)

This RFO solicited contracts with generators that would increase the amount of Renewable Portfolio Standard ("RPS")-eligible generation in PG&E's portfolio. PG&E's goal is to increase the amount of RPS-eligible generation from 13% currently, to 20% by 2017 (to comply with the California RPS requirement). PG&E sought offers with the intention of entering agreements to purchase energy and capacity from the respondents.

3.1.2 2004 Intermediate Term RFO (closed)

PG&E solicited offers from suppliers for energy, capacity, and related power products for the period of 2005 through 2008.

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14 The RFOs listed in the table above and discussed further below are derived from those RFOs listed on the IOUs' websites. Other procurement processes or RFOs may have occurred in California that are not included in this discussion.

In this RFO process, bidders submitted an initial offer approximately one month after the RFO was announced. PG&E then selected a shortlist, and negotiated with short-listed respondents before selecting the final winner(s). PG&E would then have submitted it's choices to the CPUC in the quarterly compliance report. Although it appears that PG&E did not publicly announce the winner(s) of this process, it is interesting to note that one may be able to extract information in the future about the contract(s) signed by using the FERC EQR database (once deliveries begin under these contracts).

3.1.3 2004 Long-Term RFO - Facility Ownership/ Power Purchase Alternative

In this RFO (as reissued), PG&E elicited offers for the construction of new generation facilities, or for offers for energy and capacity, to be provided under long-term contracts beginning in 2008. In the RFO document, PG&E stated it "currently estimates that it will need to acquire… dispatchable capacity of approximately 1,200 MW in 2008, and an additional 1,000 MW in 2010."[15] PG&E also referenced the need to replace the energy associated with expiring Qualifying Facilities contracts (which will expire between 2006 and 2010).

This RFO process consisted of two stages. The first stage required bidders to submit initial offers, due approximately one month after the RFO was issued. From the initial offers, PG&E selected a shortlist, and requested final offers (expected to be due in September 2005). From the final offers, PG&E then will select the winner(s). To select the winner(s), PG&E will evaluate each bid in terms of its price, fit with PG&E's portfolio, its impact on PG&E's system, the qualifications (financial and otherwise) of the submitter, environmental characteristics and other criteria.

The requirements for participation in the RFO include a mandatory deposit of $5/kW (e.g., $2.5 million for a 500 MW plant) in the form of cash or a letter of credit. The deposit is returned at the conclusion of the RFO process for that bidder; it is forfeited if the bidder withdraws a binding offer or is found to have materially misrepresented pricing or other information submitted. In addition, suppliers need to meet an online date of no later than 2010 (but no earlier than 2007), with a stated PG&E preference for resources that begin commercial operation in 2008. In this regard, the developer would have to be already well along in the development process prior to submitting an offer. [16] The submitter must also prove control of the proposed site (by ownership or long-term lease, or option on the preceding) no later than the final bid deadline (5-6 months after the RFO release). PG&E also ranks and selects bids based on each proposed project's progression in terms of siting, permitting approvals, environmental impact studies, interconnection approvals, etc., however none of these factors are subject to explicit requirements.

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15 PG&E's 2004 Long Term Request For Offers – Facility Ownership

16 See Attachment D, *Power plant project development timelines in California, 1997-2005*, prepared by Dr. Kevin Kennedy, Energy Commission staff for more complete details of the lead times required for planning new facilities.

3.1.4 2005 Renewables RFO

This RFO solicited contracts with renewables generators that conform with the California RPS standard. The contracts sought would have delivery terms of 10 to 20 years, and would start delivery as early as 2006. According to the RFP, PG&E is seeking 1% to 2% of its retail sales volume - 700,000 and 1,400,000 MWh - to come from renewables. As with the 2004 long-term RFO, PG&E is seeking either turnkey PPAs or agreements to purchase power plants on a turnkey basis. The deposit required is $3/kW of the bid.

The process for this RFO differs slightly from previous ones. Though the RFO will still use a two-stage format, the initial bids will be binding in this case. There will be a short-list of candidates but no "final bid" stage. Once the short-list has been selected, PG&E is planning to consult with its PRG prior to executing the final agreements.

3.2 Southern California Edison RFOs

SCE has issued two RFOs recently.

3.2.1 Southern California Edison 5-Year Request for Offers

In the 5-year RFO,[17] SCE solicited offers for:

- Unit Contingent Tolling Agreements (Dispatchable);
- Non-Dispatchable Qualifying Facilities Resources;
- Unit Dispatch Call Options; and
- Daily Call Options.

The products were requested for terms of up to 56 months, with delivery beginning no earlier than May 1, 2006; with the last delivery no later than December 31, 2010.

The RFO was released on July 1, 2005. The deadline for submittals was July 20, 2005. From the submitted offers, SCE is supposed to select a short-list (expected in early August 2005), and enter into negotiations with the short-listed respondents. Final contracts are expected to be signed in September 2005.

SCE expressed the most interest in offers having one of four characteristics:

1. dispatchable, low capacity cost, higher heat rate tolled units located in Los Angeles (energy delivery point within SP-15), providing high availability during peak demand months,

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[17] *See* SCE's 5-year RFO website, see http://www.sce.com/AboutSCE/Regulatory/SCEIssues5YrRFO/.

2. lower cost, higher strike heat rate daily call option offers for super-peak hours,
3. dispatchable unit contingent tolling transactions, or
4. Qualifying Facility ("QF") resources that are dispatchable during on-peak periods or curtailable during mid-peak and/or off-peak periods (QF resources delivering into SP-15 need not be dispatchable).

3.2.2 Southern California Edison Request for Offers for New Generation Resources

In this RFO, SCE sought to acquire capacity from new generation (to be online between 2006 and 2008), along with the rights to schedule and dispatch energy and ancillary service, under a power purchase agreement ("PPA").

The RFO was released on April 22, 2005. Indicative offers (comparable to initial offers in other IOUs' RFOs) were due June 1, 2005. SCE was then supposed to select a shortlist from the indicative offers (respondents were notified on June 22, 2005), and request final offers from the respondents. After negotiations on a definitive agreement, SCE will select the winners from the final offers (expected in September 2005).

To participate in the RFO, submitters were required to propose new facilities; demonstrate an initial delivery date between June 1, 2006 and August 1, 2008; and place a deposit that is the greater of $500,000 or $5,000 per MW of contract capacity. The evaluation criteria are similar to those under the PG&E 2004 Long-Term RFO, and consider issues of effect on SCE's portfolio, its impact on SCE's system, the qualifications (financial and otherwise) of the submitter, environmental characteristics, and other criteria.

It is important to note that this RFO has unique cost recovery conditions attached with it. SCE has stated that it does not want its bundled rate customers to bear the entire cost of these contracts. As such, SCE has proposed to the CPUC that all electricity customers in SP-15 zone of the CAISO control area bear the costs of the contracts and has asked CPUC to support this cost recovery mechanism as SCE seeks FERC's authorization to recover such costs in transmission rates.[18]

3.3 San Diego Gas & Electric RFO

3.3.1 San Diego Gas & Electric Renewable RFO

SDG&E issued an RFO seeking California RPS-eligible renewable portfolio resources. SDG&E was seeking enough capacity to achieve an overall portfolio compliant with the state's 20% RPS standard by 2010. The RFO indicated a minimum facility size of 1 MW if the resource was within SDG&E's service area, or 5 MW if the resource was outside SDG&E's service territory.

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18 *See* Administrative Law Judge Judge's *Ruling Regarding June 3, 2005 Motion, Prehearing Conference, and Prehearing Conference Statements* in A. 05-06-003; July 18, 2005.

Options for the RFO included PPAs, PPAs with a buyout option, or the development of a facility to be sold to SDG&E. The winners must be able to deliver starting no later than 2010.

The RFO was released on July 1, 2004, with the deadline for offers of August 12, 2004. Then SDG&E was to have selected a short-list from the offers, and entered into negotiations with the short-listed respondents, prior to selecting the final winners.

3.4 The implications to RFOs of releasing aggregated summary tables

The economic theory of signaling has implications for the impact of the proposed release of the aggregated summary tables on future RFOs. The aggregated summary tables would provide signals about the IOUs' needs to new developers and provide an opportunity for new developers to prepare to respond to future RFOs credibly (i.e., negotiate land rights, option equipment, etc.). This would level the playing field between well-positioned existing suppliers and potential new suppliers. Auction theory suggests that this would lead to more aggressive competition, resulting in a more competitive procurement process and effectively lower procurement costs. The benefits of signaling is closely related to the theories I discussed in my initial testimony about the benefits of the release of certain information in auction environments where there are a mixed group of bidders, some with more knowledge and sophistication than others. In such an auction environment, the release of information that "levels the playing field" between possible bidders benefits the buyer(s) because it removes some of the common uncertainty in the value of the underlying service being auctioned, thus reducing the "winner's curse" problem I discussed in my initial testimony, and motivates more aggressive competition. The publication of the aggregated summary tables would provide more useful long-term planning-level and bundled customer information than the RFOs, thereby opening the market to more participants by giving them better data resources on which to base their investment decision.

This is especially relevant to procurement in California, because long-term energy has the characteristics of a common value good.[19] According to Bulow and Klemperer, "'common-value' assets [are] assets [that] all buyers would value equally if they shared the same information."[20] Electricity (especially long-term forward transactions for energy and capacity), like many other commodities, is typically considered to have a high degree of common value properties because of resale potential and single market-clearing price mechanism that on an ex-post basis assigns each unit of electricity (each MW in the thousands of MW that "cleared" the market at that point in time) a single market-clearing price. In other words, a MWh of electricity will have the same market clearing price, no matter who generated it, who buys it, who sells it, or who buys and resells it. Though, understandably, each supplier may be differently impacted

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19 Auctions are distinguished in theory and empirical analysis along a number of dimensions, one being where the service or good being auctioned has common value or private value traits. Under a private value auction, each bidder's value is a function of that bidder's particular situation. In other words, knowledge of another bidder's private valuation of a product or good will not change how one values that same product or good. In contrast, in a common value auction, all bidders would have the same value for the product on an ex-post basis, though each may have private information about the uncertainty driving the value.

20 Jeremy Bulow and Paul Klemperer, *Prices and the Winner's Curse*, Rand Journal of Economics, 2002.

by the sale or purchase of the same MWh of electricity, because of his other trading positions and portfolio obligations.

Common value auctions are also denoted in the literature as "affiliated" or "correlated value" auctions because information about how other bidders' value the same good may affect how one bidder formulates his own valuation given the uncertainty. Clearly, there are many key variables which are highly uncertain, and which drive the price of electricity (such as gas prices); each bidder may have a proprietary outlook about these variables, but no one is certain about what the future price of gas would be, and all participants are commonly affected by this uncertainty. The gas price driver underlying electricity prices in California is one example of the "affiliation" concept that, in my opinion, qualifies long-term electricity markets as common value auctions. The common value properties of long-term electricity markets is much higher than, for example, in real-time markets for electricity. Characterizations of electricity as a private value auction have been made by experts primarily in regards to the real-time market where purchases of electricity are made for own-consumption. The IOUs, arguably, would like us to believe that is the case for their long-term procurement process as well, but the fact remains that the IOUs can and will trade around that electricity they may acquire through the RFOs and other procurement processes for many years to come, subject to the changing market conditions and the ongoing evolution of uncertainties and market risks.

The common set of uncertainties regarding the future value of energy, i.e., gas prices or the demand for energy by the IOUs, drives the need for the release of aggregated summary tables for the benefit of consumers. The perception by some suppliers that their competitors have better information dilutes the competitiveness of the entire auction process for common value goods and thus causes inefficient market outcomes. Auction theorists, in particular Robert Wilson[21] and Paul Milgrom[22], have shown that in common value auctions, introducing information that "levels the playing field" and substitutes[23] for the perceived "better information" of the sophisticated suppliers will result in greater competition and thus in a better outcome for the procurer (in this case, the IOUs and their ratepayers). In summary, the release of the aggregated summary tables and the information on the long-term needs of the IOUs will substitute for the existing knowledgebase and as a result of the leveled playing field, will further support the overall success of future RFO processes rather than cause harm to ratepayers.

Another beneficial aspect of the NOI involves the signaling properties of the aggregated summary tables. Due to the time-intensive nature of conventional plant development, developers must almost certainly have completed most of the pre-development process before the RFO is issued, or they run an unacceptable risk of losing their substantial bid deposits, not

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21 Robert Wilson, *A Bidding Model Of Perfect Competition*, Review of Economic Studies 44: 511-518, 1977.

22 Paul Milgrom, *Putting Auction Theory to Work,* Cambridge University Press, 2004.

23 In a common value auction setting, each supplier's estimate of the value of future energy is interdependent due to common set of uncertainties and the potential for resale in the future. Thus, the values estimated by any one supplier can have an impact on all suppliers, and substitute information can help to improve the quality of the estimates.

to mention the opportunity cost of having such funds tied up in an RFO for which they were not well-prepared. For a new conventional power project to be a viable and credible option in a competitive solicitation process, a developer will need to show that he has secured land and key equipment and has started the permitting process. Purchasing or optioning land and negotiating with major equipment manufacturers is a time consuming task because it involves preparing initial technical specifications for the plant, pre-selecting an equipment vendor, reviewing various technical specifications of the site (including due diligence on proximity of transmission and fuel infrastructure, water rights, etc.), and pre-review of any possible CEQA issues with respect to preferred site. Typically, this "soft development" process takes upwards of six months, if not longer. RFOs typically require first bid submission within four to six weeks of the RFO package going out. If selected for the next round, bidders will typically have limited room to adjust their bid price. Thus, a developer who has waited for the RFO to be issued will not have the necessary lead time to get the "soft development" process complete as described above in order to credibly respond to the RFO. Release of the aggregate summary tables will help alleviate this disconnect between RFO process timeline and preparation time by giving new developers insights into the future needs of the IOUs, early enough for them to begin the development process.

In addition, because the CPUC requires that the planning reserve targets apply to each month, in addition to the annual requirement. Certain technologies or alternatives may be better suited than others to address the monthly nature of the required planning reserve margin target. The quarterly aggregated summary tables will be able to signal to the market ahead of any RFO on the seasonal needs of the IOUs, and thus motivate optimal investment response, whether it is for generation energized only in certain seasons, or a program to incentivize industrial customers to provide demand-side management.

By signaling to suppliers the optimal time to enter and exit the market, the release of the aggregate summary tables will also help to promote competition and dynamic efficiency gains for the California energy sector, which in the long run will benefit consumers and ratepayers of electricity. This is another area where Dr. Plott's study lacks applicability to the California market. Dr. Plott discloses the static nature of his experimental study. Furthermore, the lack of a control group in the experimental analysis obstructs measurement of the social efficiency consequences of asymmetric information release. Dr. Plott also concedes on this point in a footnote: "Our experimental design does not include sessions without information disclosure, so it cannot determine whether forced disclosure increases or decreases efficiency."[24] The important potential benefits of signaling needs to be incorporated into the experimental study design, by allowing participants to choose to enter/exit and by including a control group, in order to gain a better appreciation of overall net benefits of the aggregated summary tables.

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24 *See* Attachment A to Plott's testimony, page 14.

3.5 Evidence from Australian markets

It is always useful to look to practical applications of theory. The information release policies in the Australian National Electricity Market ("NEM") are a classic example of the real world extension of the auction theories discussed above.

The NEM was formed in December 1998 and is operated as a zonal power pool market similar to the market for energy that Cal-PX used to operate, and the energy market in some ways operated by other ISOs in the Northeast U.S., and other deregulated power markets elsewhere around the world. In the initial stages of establishing the NEM, market designers had to deal with the issue of transparency and market power. Some stakeholders had proposed to release as much market information as possible to all market participants, including the bids and offers of all market participants. Other stakeholders argued that too much information could be manipulated and lead to possible market power problems. Eventually the Code Administrator (the regulatory authority) decided to publicly release the full set of market information, including all bid and technical data, immediately after the end of each trading day. At the time, it was argued that this transparency was vital to create a well-functioning market and a level playing field for the diverse set of participants.

NEMMCO (the market operator) provides load forecasts, pre-dispatch data, dispatch data, price sensitivity analysis, as well as medium (seven days) and long-term (two years) forecasting of supply and system adequacy.[25,26] Also, NEMMCO releases on a next day basis every bid made by every market participant the previous trading day, whether or not the bid was successful.[27] This gives all market participants access to tremendous competitive information about other bidders' opinions on market conditions and prices. Despite the overwhelming amount of sensitive market information released daily, the NEM functions very well. In fact, Peter Adams, the current Code Administrator attributes part of NEM's success to the volume of data released and the amount of education and support that this information provides to weaker players in the market.

As stated by Peter Adams recently, "our reporting arrangements [e.g., release of bid data and other information], provided information to some of the lesser [sic] sophisticated and smaller players who we were encouraged to come into the marketplace."[28] The Australia example is a real world corollary to the economic theories about the positive impact of the release of information in a common value auction.

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25 NEMMCO, *An Introduction to Australia's National Electricity Market.*

26 *See* http://www.nemmco.com.au/.

27 *See* http://www.nemmco.com.au/data/csv.htm.

28 *See* Peter Adams, *Market Monitoring: The Australian Experience* June 10, 2005; Transcript from a presentation by Peter Adams before a June 10, 2005 workshop at the Public Utilities Commission of Texas (Project No. 28500).

4 Conclusion

In his testimony on behalf of SCE, Dr. Plott bases his conclusions about the California energy market on the assumption that the market operates as a series of pair-wise negotiations (based on the design implicit in his experimental study, *Forced Information Disclosure and the Fallacy of Transparency in Markets)*. However, the fact that RFOs are the most common approach to long-term procurement in California suggests that the long-term market is best described as a series of auctions. Moreover, buyers (i.e., IOUs) are not limited to any single RFO to procure for their long-term needs. Indeed, they can propose to build their own infrastructure and also procure through a series of RFOs mixed with spot purchases and negotiations. The aggregated summary tables would release information about this highly dynamic long-term market.

Because of the nature of auctions where the product or service involved has a common value to all participants (as is the case with electricity), the release of substitute information to private conjectures, like the supply-demand expectations embodied in the aggregated summary tables, will have the effect of promoting competition among potential suppliers. This can only benefit the ratepayers. This has indeed been the case in the Australian National Energy Market, where the regulators deliberately chose a very high level of information release in order to promote competition.

Generally, notwithstanding differences in the format of the procurement process (i.e., whether it is a single round or multi-round auction process), or the size of the potential bidders, release of substitute information will increase the confidence of all potential bidders about the benefits of participation. As noted by renowned auction theorists, Jeremy Bulow and Paul Klemperer "[n]o amount of bargaining power is as valuable to the seller as attracting one extra bona fide bidder."[29] Though PG&E's witness Kuga contends that the RFOs already release some similar information, they simply do not do this in a timeframe that would incentivize and accommodate new participants, especially given the three year, nine month time observed timeframe for developing, permitting and constructing new plants in California.[30] Therefore, in addition to helping "level the playing field" between existing suppliers, the aggregated summary tables may help "level the playing field" between existing and potential new suppliers.

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29 Jeremy Bulow and Paul Klemperer, *Auctions versus Negotiations*, American Economic Review, March 1996.

30 For further information, please refer to Attachment D, *Power plant project development timelines in California, 1997-2005*, prepared by Dr. Kevin Kennedy, Energy Commission staff.

Attachment C

***The Myth Of California IOU Uniqueness*, Prepared By Dr. Michael Jaske, Energy Commission staff.**

The Myth of California IOU Uniqueness

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August 12, 2005

Summary

In their appeals of the California Energy Commission (CEC) Executive Director's resource plan aggregation proposal, the investor-owned utilities (IOUs) argue that the experience of the electricity crisis of 2000/2001 suggests that the proposal will allow market power to be created and used adversely against the interests of bundled service ratepayers. [Pacific Gas and Electric Company witness Kuga, July 8, 2005, page 2] The IOU's response to this perceived threat is to recommend that the CEC hold long-term planning data confidential. However, this approach to planning data is rare amongst the major utilities of the West.

This fact led CEC staff to investigate whether the California IOUs are somehow uniquely different from other IOUs around the West. Are they subject to loss of load from core/non-core, resumption of direct access, community choice aggregation, municipalization and other extraordinary means that differ from the normal uncertainty about economic/demographic growth. Alternatively, do they have some unique level of exposure in the bilateral contract market to the rapaciousness or collusive tactics of generators and traders? Is Pacific Gas & Electric Company's (PG&E) desire to protect quarterly energy data a consequence of some unique level of exposure to hydroelectric generation variations? Review of the circumstances of California IOUs finds that the other IOUs around the West have equal or greater uncertainties about these matters compared to those of the California IOUs. The CEC staff finds no unique factors that justify a departure from standard utility practice for reporting load forecasts, resource plans and resource needs.

Projected Resource Mix Considerations

The California IOUs may believe that their resource situation is somehow different from that of other utilities in the West, and that the differences justify withholding of the summary resource planning tables proposed by the Executive Director in the Notice of Intent (NOI). Table 1 provides a comparison of the major investor-owned utilities in the West with the three California IOUs.[1] Three measures are reported: (1) share of projected loads covered by existing and planned resources, (2) share of existing and planned resources in 2009 that are bilateral contracts, and (3) share of existing and planned resources in 2009 that are hydroelectric generation. Making this comparison for 2009 is only possible because it is common that Western utilities report such resource planning

[1] This table includes the same major Western IOUs described in the direct testimony of Michael Jaske dated July 8, 2005 submitted in the CEC *2005 Energy Report* proceeding in which the IOUs have appealed the Executive Director's resource plan aggregation proposal dated June 3, 2005.

information in publicly accessible ways and because of the NOI. California IOUs would prefer not to provide such information, and this table could not have been constructed from their original public filings to the CEC. As a result of the NOI process, the IOUs have agreed to more disaggregated energy summary information than they originally provided, and this table can now be constructed to contrast the share that specific categories of resources represent of the total amount of existing and planned resources.

Reliance Upon Bilateral Contracts

Examining the projections reported in Table 1, it is clear that the percentage that bilateral contracts are of existing and planned resources for the California IOUs does not exceed the level of several other Western IOUs.[2] Of the three California IOUs, only San Diego Gas & Electric even comes close to the levels of PacifiCorp West and Public Service Company of Colorado. Within California, Sacramento Municipal Utility District (SMUD) has the second highest reliance upon bilateral contracts. So the level of bilateral contracting that the three California IOUs undertake is no greater than, and generally below, that of most Western IOUs. These other utilities may well share the California IOU concerns about exposure to "market power" risks, but withholding of long term planning information from the public does not appear to be a mitigation strategy shared by these other utilities.

Further, these purchases are made from the same pool of independent generators and other utilities that all of the utilities in the West purchase from. The spot market purchases and longer term bilateral contracts the California IOUs utilities engage in are not somehow separated from the rest of the West. Those utilities reporting individual resources in their integrated resource plans, rather than just aggregated resource categories, reveal all sort of contractual relationships with one another. As examples, Idaho Power buys from City of Anaheim, PacifiCorp has long-term contracts with Arizona Public Service (APS), Portland General Electric (PGE), Public Service of Colorado, Sierra Pacific Power and Southern California Edison, among others. The paper prepared to describe the Federal Energy Regulatory Commission (FERC) Electric Quarterly Report data series illustrates with some examples what the FERC database demonstrates conclusively, all of the LSEs in the West purchase from and sell to a common market of independent generators and generating facilities owned by the LSEs themselves.[3] Thus, the percentage exposure shown in Table 1 creates the same general sorts of risks for utilities and other LSEs outside of California as it does for the three California IOUs.

Use of Hydroelectric Generation Resources

PG&E expresses concern that disclosing its reliance upon hydroelectric generation on a quarterly basis would reveal too much about both deficits it needs to fill from other

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[2] The California IOU data excludes the allocated Department of Water Resources (DWR) contracts, which the IOUs did not enter into voluntarily.

[3] Attachment E, *Guide to the FERC Electric Quarterly Reports: availability of specific contract and transactions data,* August 12, 2005, prepared by London Economics International, LLC.

market purchases or surpluses that it seeks to sell in the market. [PG&E Appeal, June 17, 2005, page 3] [PG&E Testimony, July 8, 2005, Kuga Attachment A, page 6, para. 14] Examining hydroelectric generation as a share of existing and planned resources reveals that PG&E's share (highest among California IOUs) is much smaller than those of Avista, PGE, and Puget Sound Energy (PSE). The values for SMUD and PacifiCorp West are close to those of PG&E using an annual energy measure. (It is impossible to discuss 2009 monthly or quarterly shares in a public document due to PG&E's refusal to allow quarterly or monthly aggregated summaries to be published.) Of these utilities, Avista, PSE and SMUD all report generating resources and resource need information on a monthly basis, and do so on a short-term forecast basis, e.g. 2005-2007. Thus other utilities report much more detail, and much closer in time than the post-2008, quarterly resource plan summaries that the Executive Director proposes to release. The practice of these utilities of disclosing future planning information is at odds with PG&E's appeal even though they have comparable hydroelectric generation exposure.

Regulatory Jeopardy Affecting Load

Another possibility is that the California IOUs believe they face greater risks associated with potential loss of load. [Kuga, page 4] However, it is common for non-California IOUs to report the very planning data the IOUs seek to protect even in the face of loss of load jeopardy. Table 2 reports the same set of Western IOUs as in Table 1 and notes the apparent jeopardy of each utility from direct access, other forms of change in load responsibility from regulatory decisions, and other firm sales uncertainties (principally expiration of contracts to closely associated municipal utilities). Some IOUs operate in states where the relevant state authority has created opportunities for retail customer choice and some do not. Many IOUs face some degree of risk from expiration of firm sales contracts that for planning purposes essentially add to native customer load, frequently to small municipal utilities that may opt to find another supplier. In Table 2 there is no apparent correlation of disclosure practices with the presence or absence of retail choice opportunities.

APS, PacifiCorp, PGE, PSE and Sierra Pacific all provide load forecasts and resource plans at least as detailed as the CEC Executive Director's aggregation proposal and each of these utilities is subject to some degree of retail choice jeopardy. Although few customers have selected alternative suppliers, the planning processes that each of these IOUs undertakes must address the risks from loss of load.

Northwestern is perhaps the premier example of an IOU that is subject to loss of load through retail choice, and explicitly plans for this uncertainty by creating and publicizing alternative scenarios. Northwestern provides the annual capacity value of its resources on an individual resource basis, not merely the sum of resource categories as aggregates. PGE and PSE each explicitly mention loss of customer load in developing the load forecast they expect to serve and thus need to acquire resources to cover.

In addition, note that the legislative and regulatory decisions that create the risks that the California IOUs are concerned about take place in public processes. Legislation to create a core/non-core market is not going to be suddenly revealed to the IOUs after they have made resource commitments. California Public Utilities Commission (CPUC) decisions to allow a specific community choice aggregator (CCA) to move forward will be made in a public proceeding with plenty of notice and examination of the very issue of loss of load, the costs that might be stranded, and appropriate surcharges on the CCA's customers to recover such costs. The proposed annexation of major portions of Yolo County to SMUD resulting in load loss by PG&E has filled the public media. Thus, the mere possibility that future decisions could lead to loss of existing load should not provide a justification for withholding planning data. In fact, such long-term planning information is very likely to be used as the basis for determining whether or not there are stranded costs that such alternative supplier's customers will have to repay through transitional surcharges. Thus, even if the California IOUs were to prevail in preventing the disclosure of this information now, they would very likely be proposing to use similar data in the future as the basis for determining the magnitude and duration of surcharges to recover stranded generation service costs.

Conclusion

The load forecast, resource plan and resource need disclosure practices of these Western IOUs show that bilateral contract exposure, risk due to hydroelectric generation variation, and regulatory jeopardy to load loss or firm sales contract expirations are not unique to California IOUs. These "environmental" considerations are a portion of what the resource planning process must deal with. These and other considerations reveal some of the uncertainty about future loads or the performance of resources which the resource planning process simply has to be able to address. The review summarized in this paper does not find other utilities withholding the planning information that the California IOUs want to withhold even though the "environmental" factors of these utilities have comparable proportions to those of the California IOUs. Not even the degree to which 2009 load forecasts are covered by existing and planned resources additions seems to make a difference in desires to withhold planning information. These considerations provide no justification for California IOUs withholding annual capacity or quarterly energy values.

Regarding all three California IOU desires to withhold annual capacity values for the needs of their bundled service customers, every one of the utilities on Table 2 except the three California IOUs and Northwestern report annual capacity for their equivalent to bundled service customers needs.

Regarding quarterly capacity values, none do so directly, but SMUD, APS, Avista, and Idaho Power report monthly capacity for resources, resource need or both.

Regarding SCE's and PG&E's desires to withhold quarterly energy summary data, SMUD, Avista, Idaho Power, and PSE all report monthly resource need values for energy even though they have greater exposure to risk of hydroelectric generation variation than does PG&E. By comparison to these utilities, SCE has little hydroelectric generation, so this cannot be a rationale that justifies their desire to withhold quarterly energy information. Neither PG&E nor SCE has made a reasonable case regarding the uniqueness of their circumstances compared to other utilities in the Western Interconnection to justify withholding quarterly energy summaries.

In summary, the California IOUs have not demonstrated that the Executive Director aggregation proposals for annual capacity, and quarterly capacity and energy, summary tables will cause any economic harm. Examining three possible sources of exposure to procurement risk reveals nothing unique about California IOUs. Their desires to withhold long term planning summary data are not shared by other utilities around the West. Their appeals of the NOI should be rejected.

Table 1. Comparison of Bilateral Contract and Hydroelectric Generation among Western Utilities

	2009 Projections (Annual Gwh of Energy)						
Utility	**Forecast**	**Total E&P Resources #**	**Load Coverage(%)**	**Bilateral Contracts**	**Contract Share (%)**	**Hydro Generation**	**Hydro (%)**
Pacific Gas & Electric ±	81592	70171	86%	3585	5.1%	15983	22.8%
Southern California Edison ±	86322	81856	95%	1494	1.8%	4679	5.7%
San Diego Gas & Electric ±	17814	17240	97%	5167	30.0%	0	0.0%
Sacramento MUD	11930	11098	93%	2311	20.8%	1747	15.7%
Los Angeles Dept Water&Power	29597	29613	100%	256	0.9%	1718	5.8%
Arizona Public Service ##	33982	36334	107%	833	2.3%	0	0.0%
Avista *	9864	11870	120%	1629	13.7%	4424	37.3%
Idaho Power ** +	3285	2995	91%	290	9.7%	1706	57.0%
NorthWestern Energy	5923	4273	72%	1650	38.6	0	0
PacifiCorp, West **	3686	3848	104%	1461	38.0%	681	17.7%
PacifiCorp, East **	7983	7718	97%	700	9.1%	100	1.3%
Portland General Electric *	22259	15111	68%	4319	28.6%	5028	33.3%
PSC of Colorado **	8071	6819	84%	2177	31.9%	34	0.5%
Puget Sound Energy ***	2227	2004	90%	274	13.7%	511	25.5%

Notes:

\# Existing and Planned (E&P) resources exclude generic, unidentified resource additions needed to balance system load.
\## APS load forecast taken from 2004 FERC Form 714 filing.
± Bilateral contracts exclude long-term DWR contracts to provide comparable data for contracts entered into voluntarily.
* Data converted from average megawatts to energy.
** Data cited in capacity terms in MW at summer peak using dependable summer capacity values.
*** December 2008 average megawatts converted to energy.
\+ Estimated due to incomplete contract reporting.

Table 2. Correlation between Disclosure of Load and Resource Forecasts and Regulatory Jeopardy Affecting Load

Utility	Public Disclosure	Regulatory Jeopardy Affecting Load	
		Retail Choice	Other Uncertainty about Loads
PG&E, SCE and SDG&E	Period: 2006-2016 Annual E for load, resource need and resource categories	Direct access suspended until DWR contracts completed.	Community choice aggregation regulated by CPUC processes. Municipalization governed by state law
SMUD	Period: 2006-2016 Monthly E&C for load, resource need and specific resources	At SMUD's discretion to allow on a non-discriminatory basis	SMUD exploring annexation of a portion of PG&E service area with all "buy-out" costs paid by former PG&E customers
Arizona Public Service	Period: 2007-2011 Monthly C for load and resource need Monthly E for resource categories	According to Arizona law, all of APS's load is potentially subject to loss through retail access opportunities that end-users may elect	Not stated
Avista	Period: 2004-2023 Monthly E & C for load and resource need Annual E for resource categories	Not permitted	A 150MW dispatchible capacity to PGE in exchange for return energy agreement creates additional system load uncertainty
Idaho Power	Period: 2004-2013 Monthly E & C for load and resource need Annual E & C for specific resources	Not permitted	Firm sales to municipalities have contractual termination dates and opt out provisions
NorthWestern Energy	2004-2023 Annual E for loads Annual C for existing resources (scenarios for loss of load)	According to Montana law, Northwestern is the default generation service provider and its entire load is subject to loss from alternative suppliers	Not stated
PacifiCorp	Period: 2006-2025 Annual E & C for loads and resource need Annual C for specific resources	According to Oregon law, a limited portion of PacifiCorp's Oregon load is potentially subject to loss through retail access opportunities that end-users may elect	PacifiCorp, West load adjusted downward for expiration of Clark Co PUD sales agreement
Portland General Electric	Period: 2005-2022 Annual E & C for loads, resource need and specific resources	According to Oregon law, a limited portion of PGE's load is potentially subject to loss through elective retail access opportunities of end-users	PGE also allows large customer opt out from cost-of-service rates, which creates additional a "dual" path of financial uncertainty
Public Service Company of Colorado	Period: 2004-2033 Annual E & C for loads Annual C for resource need and resource categories	Not permitted	Not stated
Puget Sound Energy	Period: 2006-2025 Annual E & C for loads and resource need Annual C for specific resources Monthly E for loads and resource need for 2006 only	Not permitted	As a result of a settlement agreement, a limited number of large industrial customers have the option to procure generation services from alternative suppliers
Sierra Pacific	Period: 2004-2024 Annual E & C for loads Annual C for resource needs and specific resources	According to Nevada law, large customers in SP's service area are provided retail access opportunities that end-users may elect	Not stated

Note: E = energy, C = capacity. For sources, see Jaske Testimony, July 8, 2005, Table 2.

Attachment D

Power Plant Project Development
Timelines In California, 1997-2005**,**
Prepared By Dr. Kevin Kennedy, Energy Commission Staff.

POWER PLANT PROJECT DEVELOPMENT TIMELINES IN CALIFORNIA, 1997-2005

Kevin M. Kennedy, Ph.D., California Energy Commission

August 12, 2005

The following table and chart show the development timelines for the eighteen power plants[1] permitted by the California Energy Commission that applied for permits starting in 1997 and are currently online.[2] This information was developed by staff in the Energy Commission's Siting Office to illustrate the length of time it has taken in the last decade for a project developer to take a large generation project from initial preparation of an application to completion of construction in California.

The table lists the projects in the order in which they came online, with peaker projects shown in italics. The chart shows the peaker projects at the top, with the peakers and non-peakers then listed in the order in which they came online. While the Energy Commission staff has specific information on the timing of these projects from the point when an application is initially filed, less information is readily available on the amount of time needed during the pre-application stage. The table and chart show a generic seven-month period, which is consistent with the typical time needed to prepare an Application for Certification (AFC) to file with the Energy Commission. This does not include the additional time needed for developers to scope the project and identify a site.

For these projects, the average length of time from starting to prepare an AFC to going online was three years and nine months. For peaker projects, the average was two years, three months. For non-peaker projects, the average was four years and two months.

[1] The table and chart actually show nineteen 'projects'. The Sunrise peaker and Sunrise combined cycle projects are listed separately on the table and chart because they had separate permitting and construction times, but are a single power plant with a total capacity of 585 MW.

[2] The Energy Commission has permitting authority for all thermal power plants with a capacity of 50 MW or greater. In addition to the projects listed here, another nine were permitted under an emergency expedited permitting process in 2001 under Executive Orders D-26-01 and D-28-01. These emergency projects are not representative of typical project development timelines, and the emergency permit process is no longer available.

CALIFORNIA ENERGY COMMISSION - OPERATIONAL ENERGY FACILITY TIMELINES 1997-2005

Projects On Line (1) (Arranged By Date On Line)	**Docket Number**	**Status**	**Capacity (MW)**	**Location**	**Date Filed**	**Data Adequate**	**Date Approved**	**Construction Start Date**	**Original On-line Date**	**Actual On-line Date**	**Total Time (approx) Yrs/Mos (3)**
Sunrise - Peaker-Texaco & Edison Mission E.	*98-AFC-4*	*Operational*	*320*	*Kern Co.*	*12/21/1998*	*02/17/99*	*12/06/00*	*12/07/00*	*7/01*	*6/27/01*	*3 Yrs/0 Mos*
Sutter - Combined Cycle-Calpine	97-AFC-2	Operational	540	Sutter Co.	12/15/1997	01/28/98	04/14/99	07/01/99	7/01	7/2/01	4 Yrs/1 Mos
Los Medanos Combined Cycle (Pittsburg) - Calpine	98-AFC-1	Operational	555	Contra Costa	6/15/1998	07/29/98	08/17/99	09/17/99	7/01	7/9/01	3 Yrs/7 Mos
Delta Combined Cycle- Calpine	98-AFC-3	Operational	887	Contra Costa	12/15/1998	02/17/99	02/09/00	04/01/00	7/02	5/10/02	2 Yrs/8 Mos
Henrietta Peaker - GWF	*01-AFC-18*	*Operational*	*96*	*Kings Co.*	*8/27/2001*	*10/17/01*	*03/07/02*	*03/08/02*	*6/02*	*7/1/02*	*1 Yrs/5 Mos*
Moss Landing Combined Cycle-Unit 1 & 2 - Duke	99-AFC-4	Operational	1,060	Monterey Co.	5/7/1999	08/11/99	10/25/00	11/28/00	6/02	7/11/02	4 Yrs/1 Mos
Valero Cogeneration- Unit 1	01-AFC-5	Operational	51	Solano Co.	5/7/2001	06/06/01	10/31/01	11/05/01	6/02	10/18/02	2 Yrs/0 Mos
La Paloma Combined Cycle- PG&E Natl. Units 1, 2, 3 & 4	98-AFC-2	Operational	1,124	Kern Co.	8/12/1998	08/26/98	10/06/99	01/01/00	3/02	1/10/03	4 Yrs/4 Mos
Los Esteros Peaker-Calpine Units 1, 2, 3 & 4	*01-AFC-12*	*Operational*	*180*	*Santa Clara Co.*	*8/6/2001*	*09/25/01*	*07/02/02*	*07/08/02*	*5/03*	*3/7/03*	*2 Yrs/3 Mos*
High Desert Combined Cycle-Constellation	97-AFC-1	Operational	830	San Bernardino	6/30/1997	12/03/97	05/03/00	05/01/01	7/03	4/22/03	4 Yrs/3 Mos
Tracy Peaker - GWF	*01-AFC-16*	*Operational*	*169*	*San Joaquin Co.*	*8/16/2001*	*10/17/01*	*07/17/02*	*07/22/02*	*4/03*	*6/1/03*	*2 Yrs/1 Mos*
Sunrise Combined Cycle - Texaco & Mission (amendment to application: 98-AFC-4)	98-AFC-4C	Operational	265	Kern Co.	5/14/2001	5/14/2001	11/19/01	12/21/01	6/03	6/1/03	2 Yrs/7 Mos
Woodland II Combined Cycle - Modesto Irrigation District	01-SPPE-1	Operational	80	Stanislaus Co	5/4/2001	5/4/2001	09/19/01	02/21/02	5/03	6/6/03	2 Yrs/7 Mos
Blythe Combined Cycle- Caithness & FPL (2)	99-AFC-8	Operational	520	Riverside Co.	12/9/1999	03/22/00	03/21/01	04/27/01	4/03	7/15/03	4 Yrs/5 Mos
Elk Hills Combined Cycle - Sempra & Oxy	99-AFC-1	Operational	500	Kern Co.	2/24/1999	06/09/99	12/06/00	06/08/01	12/02	7/24/03	4 Yrs/9 Mos
Huntington Beach Units 3&4 Steam Plant - AES	00-AFC-13	Operational	450	Orange Co.	12/1/2000	2/7/2001	05/10/01	05/31/01	11/01	8/7/03	2 Yrs/1Mos
Donald Von Raesfeld Power Plant - (Pico) Combined Cycle Silicon Valley Power	02-AFC-3	Operational	147	Santa Clara Co.	10/7/2002	11/20/02	9/9/03	9/10/03	12/04	3/24/05	2 Yrs/11 Mos
Metcalf Combined Cycle- Calpine (2)	99-AFC-3	Operational	600	Santa Clara Co.	4/30/1999	06/23/99	9/24/01	1/15/02	7/03	5/27/05	4 Yrs/5 Mos
Pastoria PhaseCombined Cycle 1 - Calpine (2)	99-AFC-7	Operational	750	Kern Co.	11/30/1999	01/26/00	12/20/00	10/3/01	1/03	7/5/05	6 Yrs/0 Mos
										Average:	**3 Yrs/9 Mos**
		ON-LINE TOTAL	**9,124**							**Peaker average:**	**2 Yrs/3 Mos**
										Non-peaker average:	**4 Yrs/2 Mos**

NOTES:

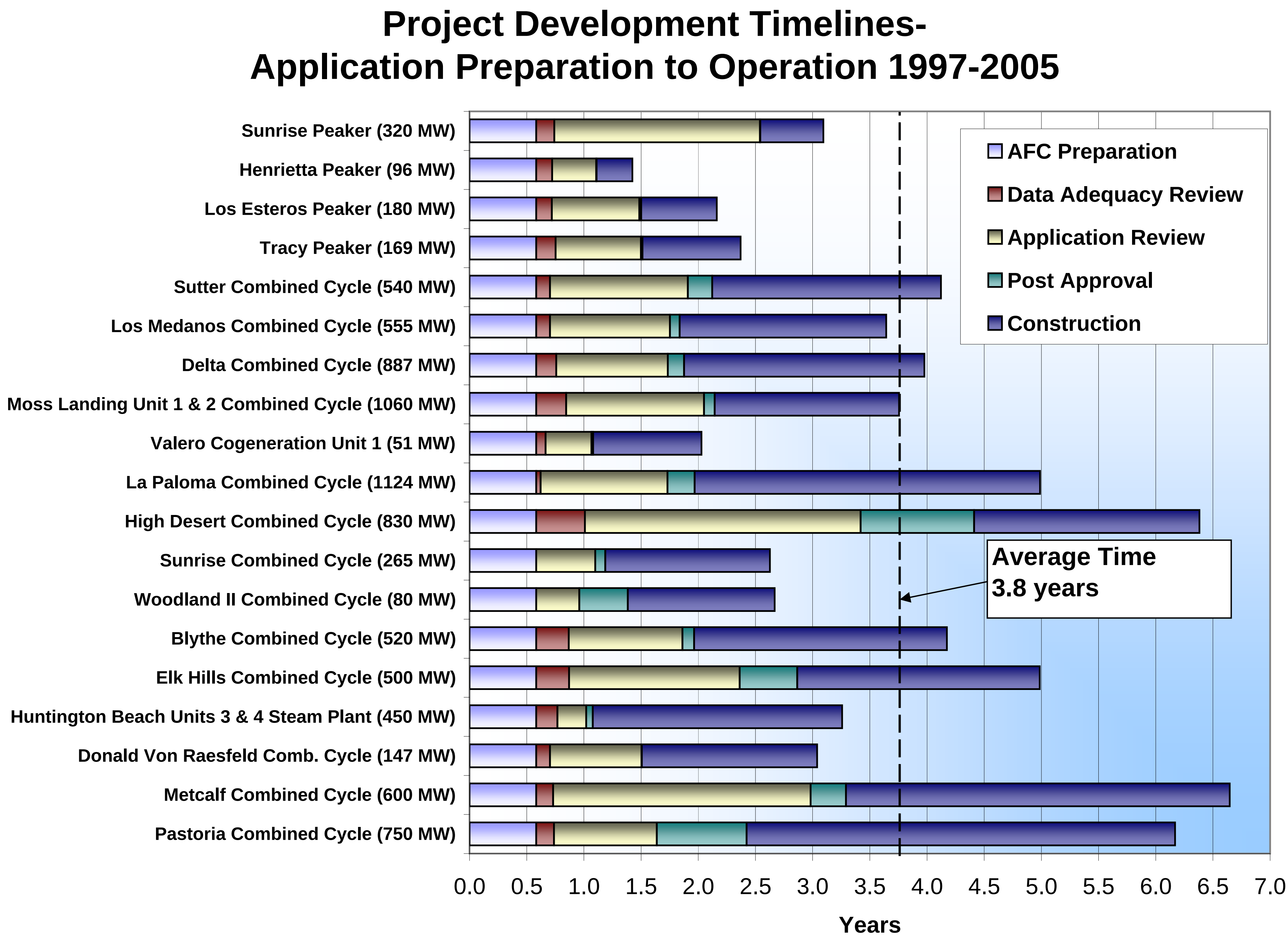
This table shows all operational power plants permitted by the California Energy Commission that filed their applications since 1997, with the exception of projects permitted in 2001 under the Energy Commission's emergency permitting authority.

FOOTNOTES:

1. Peaker projects are shown in italics.

2. Blythe I, Pastoria Phases 1 and 2, and Metcalf did not have power purchase agreements.

3. Private consultants provided informal estimates that AFC preparation time ranges from 6 to 8 months. As a result, 7 months average has been added to the total approximate time covering AFC preparation to the operational date.


Project Development Timelines-
Application Preparation to Operation 1997-2005
Sunrise Peaker (320 MW)
Henrietta Peaker (96 MW)
Los Esteros Peaker (180 MW)
Tracy Peaker (169 MW)
Sutter Combined Cycle (540 MW)
Los Medanos Combined Cycle (555 MW)
Delta Combined Cycle (887 MW)
Moss Landing Unit 1 & 2 Combined Cycle (1060 MW)
Valero Cogeneration Unit 1 (51 MW)
La Paloma Combined Cycle (1124 MW)
High Desert Combined Cycle (830 MW)
Sunrise Combined Cycle (265 MW)
Woodland II Combined Cycle (80 MW)
Blythe Combined Cycle (520 MW)
Elk Hills Combined Cycle (500 MW)
Huntington Beach Units 3 & 4 Steam Plant (450 MW)
Donald Von Raesfeld Comb. Cycle (147 MW)
Metcalf Combined Cycle (600 MW)
Pastoria Combined Cycle (750 MW)
AFC Preparation
Data Adequacy Review
Application Review
Post Approval
Construction
Average Time
3.8 years
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
5.5
6.0
6.5
7.0
Years

Attachment E

***Guide To The FERC Electric Quarterly Reports: Availability Of Specific Contract And Transaction Data*, Prepared By Julia Frayer, London Economics.**

Guide to the FERC Electric Quarterly Reports: availability of specific contract and transaction data

prepared by London Economics International LLC for the California Energy Commission

LONDON ECONOMICS

August 12, 2005

1 Introduction

California's Investor Owned Utilities ("IOU") have argued that the aggregated summary tables being proposed for release by the June 3, 2005 Notice of Intent ("NOI") are confidential or "market sensitive information."[1] Indeed, some of testimony presented by the IOUs goes so far as to say that no such similar information is available. For example, Roy Kuga, witness for Pacific Gas & Electric Company ("PG&E"), claims that "[t]elling the market exactly how much is needed would give suppliers an unfair advantage in pricing the last increment needed, especially when suppliers are not required to disclose their own cost information nor required to bid their own cost."[2] This characterization of the wholesale electricity market is not truly accurate: abundant cost and technical operating data at the plant and unit level is available on a historical basis from a variety of Energy Information Administration ("EIA") and Federal Energy Regulatory Commission ("FERC") filings that market participants are required to make. In addition, there is voluminous data on portfolio-level transactions and contracts. And futures price data from NYMEX and other brokers provides valuable information on future fuel costs for generators. Southern California Edison Company's ("SCE") witness, Kevin Cini, stated in his testimony that "[m]uch of SCE's existing supply information… is already in the public domain."[3] Indeed, very precise details on all types of power transactions between the IOUs and other entities are available for public review through the Federal Energy Regulatory Commission's ("FERC") Electronic Quarterly Reporting ("EQR") system.[4, 5]

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1 *See* McClenahan at 1.

2 *See* Kuga at 2.

3 *See* Cini at 5:17.

4 http://www.ferc.gov/docs-filing/eqr.asp.

5 The presence of the FERC EQR data also calls into question the conclusions drawn by Dr. Charles Plott in his experimental analysis. The experiment was designed to provide very limited information on market-wide transactions - buyers and sellers were only given access to their own historical trades. In support of these rules, Dr. Plott claims on page 6 of his study that, "[i]n the California wholesale electricity market contracts terms following a successful negotiation are private information, so this market does not feature any public transaction price information." However, as I show in detail in this paper, there is a great deal of publicly available transaction price information after the transaction is consummated – in fact all pertinent

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As discussed further below, the extent of contract and transaction information available (including product, price, quantity, tenure, and location of delivery) dwarfs the forward-looking planning and bundled customer information to be released in aggregated form per the NOI. Armed with the data on historical transactions, some of which are explicitly denoted as longer-term transactions (either with future expiration dates, or with no specific expiration date), counterparties to the IOUs would be able to develop a highly sophisticated analysis of recent purchase and sales strategies of the IOUs, estimate ongoing commitments, and establish the IOUs' historical and current willingness to pay for energy, capacity, and related ancillary services. In making such detailed information available to the public, FERC deemed that "the data should provide greater price transparency, promote competition, enhance confidence in the fairness of markets, and provide a better means to detect and discourage discriminatory practices."[6] How then can the IOUs argue that aggregated summary tables proposed to be released by the NOI are harmful?

This briefing paper presents a guide to the data provided in the FERC EQR filings. In Section 2, Overview of the Electric Quarterly Report, I detail the requirements of the FERC EQR system: who must file, what is typically filed, and the minimum requirements for the filings. Section 3 then compares the FERC EQR data which is publicly available against the confidential information filed by the California IOUs with the California Public Utilities Commission ("CPUC"). In Section 4, Analysis of FERC EQR data, I provide an example of the actual data submitted by suppliers and IOUs in California to the FERC EQR database. This paper concludes with a brief set of key points in Section 5.

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details for all transactions involving FERC-regulated entities are publicly available. Undoubtedly, the results of Dr. Plott's study would have been markedly different if the experiment reflected such realities.

6 99 FERC ¶ 61, 107; Docket No. RM01-8-000; Order No. 2001; Revised Public Utility Filing Requirements; Issued April 25, 2002

2 Overview of the Electric Quarterly Report

As a result of FERC's Order 2001, every public utility[7] (as defined by FERC) must file EQRs for public release. FERC generally defines a public utility as: "Every holder of a FERC tariff or rate schedule permitting the sale or transmission of electricity."[8] More specifically, an EQR is required of any corporate entity that filed any of the below with FERC:[9]

- an Open Access Transmission Tariff;
- a Cost-Based Power Sales Tariff;
- an Other Generally Applicable Services [Agreement] , or
- a Market-Based Power Sales Tariff or Rate Schedule.

The FERC EQR summarizes existing contract terms and details every single power-related transaction undertaken by the filing entity ("respondent") in the U.S. over the three months in the calendar quarter. EQRs must be filed by the end of the month after the quarter end. The FERC EQR data is available to the public as soon as a company's filing is processed, generally within 24 hours of the time a company submits the data.

In California, as well as in the wider markets of the Western Interconnect, this requirement would cover each of the three California IOUs of San Diego Gas & Electric Company ("SDG&E"), SCE, and PG&E as well as any supplier who has market-based rate authority.

There are three major portions of the FERC EQR: filer identification data, contracts data, and transactions data. The filer identification data consists of basic data needed to identify the filer, including name, address, and Dunn and Bradstreet number ("DUNS"). The filer identification data must be submitted every quarter, regardless of whether or not any sales were made.

Data must be filed quarterly for every effective contract, and every transaction covered by an effective contract. Data is available for every quarter, starting with the fourth quarter of 2002. A brief examination of first quarter 2005 (Q1 2005) FERC EQR data shows that the California IOUs purchased energy and capacity; reported booked out[10] power; and sold products including

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7 The FERC definition of public utility includes both traditional public utilities and power marketers. According to FERC, the definition is derived from the Federal Power Act.

8 FERC *Electric Quarterly Report Filing Requirements Guide*.

9 99 FERC ¶ 61, 107; Docket No. RM01-8-000; Order No. 2001; Revised Public Utility Filing Requirements; Issued April 25, 2002

10 In Order 2001, paragraph 279 describes book outs: "[A] "book out" is the offsetting of opposing buy-sell transactions. [A previous FERC Order] gave the simplified example of a sale of 100 MW of power from A to B and a sale of 90 MW of power from B to A, which would result in these transactions being booked-out and treated as a 10 MW sale from A to B. These booked out transactions are currently being reported, without objection, in Quarterly Transaction Reports, albeit in aggregated form."

energy, capacity, energy imbalance, reactive supply, spinning reserve, and supplemental reserve. Other types of transactions (i.e., "other") also appear, but less frequently. Reported contracts include both long-term and short-term tenures ("long-term" is typically longer than one year, as detailed in Figure 1 and Figure 2), and firm and non-firm terms.

The data provided in the contracts and filings portions of the FERC EQR is detailed below.

2.1 Contracts Portion of the FERC EQR

Each public utility must report its effective contracts on the FERC EQR. The data is filed electronically as a spreadsheet, and once filed is available to the public. The reporting requirements for each field are detailed in Figure 1 below.

Figure 1. Guide to Data Fields submitted in Contract portion of the FERC EQR[11]

EQR Filing Field	Data Requirement
contract_id	*A unique ID is required for each contract*
seller_company_name	*The Seller Company Name must be the same as the name on the applicable FERC Tariff. It must match the Seller Company Name in the ID Data and Transactions portions of the EQR.*
customer_company_name	*The Customer Company Name is the potential buyer/purchaser of the contract products, commodities and services. The Customer Company Name must be listed exactly as it is in the Transactions portion of the EQR.*
customer_duns_number	*Data Universal Numbering System (D-U-N-S) Number assigned by the Dunn & Bradstreet Corporation*
contract_affiliate	*An affiliate is a Customer that "controls, is controlled by or is under common control with the Seller." (Source: 18 CFR 358.3.)* *If the Seller and Customer are owned by the same parent company or are related in any way, the answer to the Contract Affiliate question must be Y for Yes.*
FERC_tariff_reference	*The FERC Tariff Reference is the authority applied for and granted to a Seller which specifies terms and conditions under which the Seller can make power sales. The designation can be found on the authorization sent in writing to the Seller. An example is: FERC Electric Rate Schedule No. 1. The FERC tariff reference is not a Docket Number.*

11 FERC *Electric Quarterly Report Filing Requirements Guide.*

EQR Filing Field	Data Requirement
contract_service_agreement_id	*Contract Service Agreement ID is a unique designation for each service agreement. It may be the number assigned by FERC for those service agreements that have been filed and approved by the Commission, or it can be an internal numbering system. The filer must be able to readily identify and produce a contract based on the Contract Service Agreement ID. (Source: Notice of October 21, 2002, Paragraph 12.)*
contract_execution_date	*The Contract Execution Date is the date that the contract was signed or agreed to by the Seller and the Customer.*
contract_commencement_date	*The Contract Commencement Date is the date the contract became effective; the date that sales under the contract began.*
contract_termination_date	*The Contract Termination date is a projected date, specified in the contract, on which the contract is to end. If the contract is silent on the matter, leave the field blank.*
actual_termination_date	*Actual Termination Date is the date the contract actually terminates. This could be the contract termination date, or any other date the parties agree to. This date will only be filled out after the contract has been terminated. (Source: Notice of EQR Filing Requirements Guide 24 October 21, 2002, Paragraph 14d.)*
extension_provision_description	*The Extension Provision is a descriptor specified in the contract. If the contract is silent on the matter, enter the term NONE in this required field.*
class_name	*Class Name. [Valid classes are: Firm; Not Applicable; Non-Firm; Unit Power Sale]*
term_name	*Power sales contracts with a duration greater than one year are Long-Term. Power sales contracts with a duration of one year or less are Short Term. Transmission contracts with a duration of one year or greater are Long-Term. Transmission contracts of less than one year are Short-Term.*
increment_name	*Increment Name [Valid increment names are: Daily; Hourly; Weekly; Monthly; Yearly; Not Applicable]*
increment_peaking_name	*Increment Peaking Names are defined regionally. Use the definition of Peak/Off-peak periods appropriate to the region where the contract product is sold. [Valid increment peaking names are: Full Period; Off Peak; On Peak; Not Applicable (Undefined)]*
product_type_name	*A description of the commodity or service available for sale, or being sold, a type of service or standard agreement. If a contract includes multiple products, each has to be reported separately.*

EQR Filing Field	Data Requirement
product_name	*A description of the commodity or service available for sale, or being sold, a type of service or standard agreement.* *If a contract includes multiple products, each has to be reported separately.*
Quantity	*Quantity [as specified in the contract - numeric value]*
units_for_contract	*Units [as specified, examples include KWh for energy contracts, MW for capacity contracts, etc.]*
Rate	*As a regulatory requirement, every piece of information about the rate that is specified in the contract must be provided to FERC. If the contract is silent about rate specifics and the rate is market-based, enter the term Market-Based in the Rate Description field. If the contract is market-based, but a rate (or rates) has been negotiated (e.g., an index price), that rate must be entered in the Contracts Products Rate field.* *At least one of the four rate fields (rate, rate minimum, rate maximum, rate description) must be filled out. For example, most market-based rates should state "Market-Based Rate" in the Rate Description Field. If the service does not have a rate, NA should be entered in the rate description field. (Source: Docket No. RM01-8, Notice of Revised Public Utility Filing Requirements, October 21, 2002, Paragraph 15.)*
rate_minimum	
rate_maximum	
rate_description	
units_for_rate	*Rate Units should match product names. For example, $/MW or $/KW cannot be used with Energy or Booked Out Power. $/MWh or $/KWh cannot be used with Capacity.*
point_of_receipt_control_area	*Point_of_receipt_control_area and point_of_receipt_specific_loc will be used for contract data only. (Source: Final Rule, Paragraph 354.)* *Points of Delivery (PODs) will be reported at the level of detail specified in the agreement. (Source: Final Rule, Paragraph 79.)* *For deliveries and receipts to multiple locations, multiple PODCA and PORCA entries may be used. If a contract does not have locational information, the location fields may be left blank.* *[I]f the power sale takes place at a standard trading hub, the word "Hub" should be entered in the PODCA field, and the particular hub name (using our standardized spellings in the list attached as Appendix B) should be entered in the PODSL field.*
point_of_receipt_specific_location	
point_of_delivery_control_area	
point_of_delivery_specific_location	

EQR Filing Field	Data Requirement
begin_date end_date	*Begin and End Dates apply to contract products, rather than the whole contract, and are to be used when there are multiple time frames addressed in the contract. If all products listed in the contract begin and end on the same dates as the contract does, there is no need to list dates in these Begin and End Date fields. Therefore, in most cases, these fields will be left blank. An example of when and how these fields should be used is this: in a five-year power sales contract with a different quantity and price specified for each year, the product (power) would be listed on five lines. Each listing would have a unique begin and end date and the price assigned for each year would be listed on the appropriate line. Another example is a transmission contract with several ancillary services. The transmission service and each of the ancillary services could have different begin and end dates. (Source: Notice of October 21, 2002, Paragraph 14e.)* *The Begin and End dates are not simply a duplication of the Contract Commencement, Execution or Termination dates.*
time_zone	*The Time Zone in which the sales will be made.*

2.2 Transactions Portion of the FERC EQR

Transaction data is required for every sale made under tariffs on file with FERC, including both cost-based and market-based sales.

Transmission transactions do not have to be filed if they are not related to a sale of power, nor if they are resales of transmission. Otherwise, transmission transactions must be reported. Merchant transmission negotiated rate transactions must also be reported. As with the contracts portion of the FERC EQR, the transmission data is filed electronically as a spreadsheet, and once filed is available to the public.

The reporting requirements for each field are detailed in Figure 2 below.

Figure 2. Guide to Data Fields submitted in Contract portion of the FERC EQR[12]

FERC EQR Filing Field	Data Requirement
transaction_unique_identifier	*The Transaction Unique Identifier is a company selected designation that relates multiple rows of data to a single transaction. For example, if a single transaction included capacity and energy, the Transaction Unique Identifier would be same for both lines of data.*
seller_company_name	*The Seller Company Name must be the same as the name on the applicable FERC Tariff. It must match the Seller Company Name in the ID Data and Transactions portions of the EQR.*
customer_company_name	*The Customer Company Name is the buyer/purchaser of the contract products, commodities and services. The customer company name must be listed exactly as it is in the Contract portions of the EQR.*
customer_duns_number	*Data Universal Numbering System (D-U-N-S) Number assigned by the Dunn & Bradstreet Corporation*
tariff_reference	*The FERC Tariff Reference is the authority applied for and granted to the Seller to make sales. The designation can be found on the authorization sent in writing to the Seller. The entry must be listed exactly as entered in the Contracts portion of the EQR.*
contract_service_agreement	*The Contract Service Agreement ID is designated by the utility or may have been assigned by FERC. The entry must be listed exactly as entered in the Contracts portion of the EQR.*
transaction_begin_date	*The Transaction Begin Date must be prior to the end of the reporting quarter and no earlier than the beginning of the reporting quarter.*
transaction_end_date	*The Transaction End Date and time must be after the beginning of the reporting quarter and no later than the end of the reporting quarter. The Transaction End Date and time must be later than the transaction begin date and time.*
time_zone	*The Time Zone reported is relative to the area in which the transaction took place. If the transaction involves more than one time zone, use the time zone that relates to the time listed for the transaction.*
point_of_delivery_control_area	*Point of Delivery Control Area (PODCA) and Point of Delivery*

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FERC EQR Filing Field	Data Requirement
specific_location	*Specific Location (PODSL) relate to the location where title to the power transfers (or would have transferred in the case of Booked Out Power). The NERC Control Area or specific location at which a power sale takes place.*
class_name	*Class Name designates whether the Product was provided on a Firm or Non-Firm basis. It may further define a transaction as a Billing Adjustment or a Unit Power Sale as described below.*
term_name	*Power sales transactions with a duration greater than one year are Long-Term. Power sales transactions with a duration of one year or less are Short Term.*
increment_name	*Increment Name should reflect the duration of the underlying commitment for which the transaction occurs. If the Seller can choose which hour to sell power, the Increment Name will be "H." If the Seller has committed to sell power over a number of hours for a coming day, the Increment Name is "D."*
increment_peaking_name	*Increment Peaking Names are defined regionally. Use the definition of Peak/Off-peak periods appropriate to the region where the contract product is sold.*
product_name	*A description of the power commodity or service sold.* *Since a transaction can be composed of numerous transaction products (power, ancillary services, etc.), each transaction is given a unique Transaction Identifier (TR1, TR2, TR3, etc..) Each transaction product should be listed separately on its own line with the unique specifications detailed. All transaction products sold under a single transaction should have the same Transaction Identifier as the rest of the transaction components.*
transaction_quantity	*Transaction Quantity. The quantity of the product in [a] transaction. This could be a whole number or it could include decimals.*

FERC EQR Filing Field	Data Requirement
Price	*Public Utilities will report actual prices for all transactions, including those lasting less than one day. (Source: Final Rule, Paragraph 254.)* *When a transaction price changes during a sale, a new row of data reflecting that change must be reported in the EQR.* *Transaction prices are actual and are not averaged.* *Rate design: Many services do not have one-part commodity rates/prices for energy sales. Utilities should use different lines for listing the different components of the rate/price (such as reservation fee, commodity price, etc.) in the Contract and Transaction Templates.*
Units	*Rate Units should match product names. For example, $/MW or $/KW cannot be used with Energy or Booked Out Power; $/MWh or $/KWh cannot be used with Capacity.*
total_transmission_charge	*Report any transmission charge related to the sale of power.* *Pure transmission sales are not reported with the exception of merchant transmission sales required by the Commission to be reported quarterly.*
transaction_charge	*The dollars and cents total of a transaction row.* *The Transaction Charge is the price times the quantity plus any applicable power related transmission charge.* *Every row of a transaction must result in a total. Do not repeat a grand total on each row of a multi-row transaction.*

3 Comparing FERC EQR data to the information filed with the CPUC

It is interesting to note that the data provided in the FERC EQR would allow any market participant to essentially produce a close substitute for the information contained in the aggregated summary tables on a historical basis. Moreover, the FERC EQRs contain the exact same information on each of the individual transactions that underpins the quarterly updates provided by the IOUs to the California Public Utility Commission ("CPUC") pursuant to the May 20, 2003 Protective Order issued in R. 01-10-024, and the Public Utilities Code 583 & General Order no. 66C.

Figure 3. Data required under CPUC protective order vs. data in FERC EQR system

Data to be provided under Protective Order		Equivalent Available in EQR	
Term Purchases/Sales	On-Peak/Off-Peak/Super Peak/Flat, Delivery Term, Energy, Notional Value, Number of Deals	Long-Term Transactions Data	On-Peak/Off-Peak/Super Peak/Flat, Transaction Start Date, Transaction End Date, Energy, Price, Transaction Value, Number of Transactions
Spot Purchases/Sales	On-Peak/Off-Peak/Super Peak/Flat, Delivery Term, Energy, Notional Value, Number of Deals	Short-Term Transactions Data	On-Peak/Off-Peak/Super Peak/Flat, Transaction Start Date, Transaction End Date, Energy, Price, Transaction Value, Number of Transactions
Energy Source	Generation/Contract Resources, Term Purchases, Spot Purchases	Transaction Data/Contract Data	Term Purchases, Spot Purchases

The data provided by the IOUs under Protective Order contains summaries of products purchased and key price indicators. Figure 4 shows that this same information can be assembled from the FERC EQR database.

Figure 4. Summary of IOU purchases by product type, Q1 2005

	Transaction Type					
	BOOKED OUT POWER		CAPACITY		ENERGY	
	Volume (MWh)	*Average Rate ($/MWh)*	*Volume (kW-month)*	*Average Rate ($/kW-month)*	*Volume (MWh)*	*Average Rate ($/MWh)*
Pacific Gas & Electric	57,500	$57.13	330	$13,000	370,092	$38.50
Southern California Edison	325,617	$54.04	978,585	$10	518,010	$46.25
San Diego Gas & Electric	69,876	$47.50	69,289	$14	240,494	$46.24

Source: FERC EQR Database

The confidential data tables filed with CPUC present information on purchases by peak period. This can also be found publicly in the FERC EQRs, as shown in Figure 5.

Figure 5. Average, minimum, and maximum prices for energy purchases, by IOU, in Q1 2005

	On-Peak			Off-Peak			All Hours		
	Min	*Max*	*Average*	*Min*	*Max*	*Average*	*Min*	*Max*	*Average*
Pacific Gas & Electric	$17.12	$71.00	$38.48	$33.00	$70.50	$57.62	$25.00	$68.00	$28.72
Southern California Edison	$2.00	$75.00	$72.03	$43.00	$68.00	$53.95	-$2.06	$74.00	$67.56
San Diego Gas & Electric	$39.50	$70.00	$46.16	$34.75	$70.00	$45.19	$0.00	$75.50	$47.30

Source: FERC EQR Database

Indeed, because each transaction is listed separately in the FERC EQR filings, more detail is publicly available under the FERC EQR system than in the aggregate reporting made by the

IOUs to the CPUC pursuant to R. 01-10-024. Additional data available in the FERC EQR filings includes transaction counterparty and point of delivery, as well as other descriptive parameters.

4 Analysis of FERC EQR data

As noted in the introduction, the IOUs claim the aggregated summary tables represent confidential data on their net position and trading strategy. Their claims effectively ignore the existing publicly available knowledgebase on the IOUs' net position and trading arrangements. To emphasize the significance of publicly available data, and specifically the wealth of information about transactions and contracts contained in the FERC EQR filings, I have assembled a number of tables and analyses of data available in the FERC EQR database.

To perform this analysis, I retrieved a small portion of the FERC EQR database. Using data for the first quarter of 2005, I retrieved data on the sales transactions and contracts of all FERC-regulated entities that conducted sales transactions in the California Independent System Operator[13] ("CAISO") with a California IOU as the "customer" (i.e., where California IOUs were purchasing services). The transactions thus sampled include sales to the IOUs that took place in CAISO, as well as some transactions with the same counterparties that occurred outside CAISO. I also extracted the entire filing that each of the three California IOUs made with FERC which documented all the IOUs' sales transactions. With this information, I formed a database of a sample of IOU purchases and all IOU sales in Q1 2005.

Figure 6 and Figure 7 present a summary of the FERC EQR transactions downloaded for the current analysis.

Figure 6. Summary of downloaded FERC EQR data from Q1 2005[14]

	Purchases		Sales	
	Transactions	*Counterparties*	*Transactions*	*Counterparties*
Pacific Gas & Electric	863	10	1840	26
Southern California Edison	1039	14	3818	43
San Diego Gas & Electric	2293	12	725	37

Source: FERC EQR Database

Figure 7. Summary of downloaded FERC EQR purchase transactions filed for Q1 2005

	Pacific Gas & Electric				Southern California Edison				San Diego Gas & Electric			
	Trans.	MWh	Avg $/MWh	Total $	Trans.	MWh	Avg $/MWh	Total $	Trans.	MWh	Avg $/MWh	Total $
Long Term	-	-	-	-	1054	56,245	$38.37	$2,157,891	104	70,530	$53.01	$3,738,794
Long Term Firm	-	-	-	-	-	-	-	-	104	70,530	$53.01	$3,738,794
Short Term	635	384,146	$50.46	$19,383,635	966	770,994	$52.94	$40,819,415	1856	198,739	$48.97	$9,732,315
Short Term Firm	515	328,368	$49.35	$16,204,934	746	703,506	$52.77	$37,121,597	1512	109,512	$49.63	$5,434,893
Other	228	43,446	$56.12	$2,437,980	67	16,384	$502.13	$8,226,970	333	41,101	$46.65	$1,917,193

Source: FERC EQR Database

13 Although the CAISO is required to file an EQR, they do not file imbalance transactions. This is in keeping with paragraph 335 of Order 2001, which states that they do not have to file their transactions if they are facilitating transactions by their members.

14 For purposes of this analysis, I have used data downloaded directly from the FERC EQR database for this analysis without any substantial independent data verification. FERC provides the data as filed by various respondents. FERC does not guarantee the accuracy of this data.

In the following figures, I use the FERC EQR data to observe key factors underlying specific relationships between suppliers and IOUs. For example, from Figure 8, it can be seen that PG&E purchased primarily from nine firms in Q1 2005 in CAISO. PG&E paid relatively similar average prices to each counterparty over the quarter but the maximum and the minimum prices varied significantly. Interestingly, some counterparty firms (like Calpine Energy Services) reported a wide range of selling prices, while others (like FPL) have a relatively narrow band of prices at which they sold to PG&E.

Figure 8. Summary of downloaded PG&E energy purchases by counterparty (Q1 2005)

Pacific Gas & Electric Company	Energy Purchases					
	Trans.	Volume (MWh)	Total Value ($)	Average Price	Max Price	Min Price
Avista Energy, Inc.	21	1,465	$79,715.00	$54.41	$62.00	$35.00
Calpine Energy Management, L.P.	27	7,235	$397,111.00	$54.89	$65.00	$45.00
Calpine Energy Services, L P	154	201,250	$4,678,626.40	$23.25	$70.00	$17.12
Coral Power L.L.C.	42	3,412	$174,097.00	$51.02	$68.00	$25.00
FPL Energy Power Marketing, Inc.	13	644	$34,520.00	$53.60	$55.00	$52.75
Mirant Americas Energy Marketing LP	65	19,332	$1,140,859.00	$59.01	$68.25	$20.00
Occidental Power Services, Inc.	71	29,509	$1,646,273.00	$55.79	$65.75	$37.75
Powerex Corp	196	81,950	$4,734,730.00	$57.78	$71.00	$37.75
PPM Energy, Inc.	163	24,114	$1,297,120.75	$53.79	$69.00	$27.00
San Diego Gas & Electric	14	1,181	$63,663.00	$53.91	$61.00	$33.00
Total	**766**	**370,092**	**$14,246,715.15**	**$38.50**	**$71.00**	**$17.12**

Source: FERC EQR Database

Similar information is available from the sell-side. Figure 9 portrays a random sample of counterparties to whom PG&E sold energy. As can be seen from Figure 9, PG&E sold over 2,726 GWh of energy in the first quarter of 2005 to this sample of counterparties, with the largest counterparty of this sample being the Western Area Power Administration ("WAPA"). Notably, the WAPA's purchase price was the lowest average price of all the other sample counterparties.

Figure 9. Sample of PG&E's energy sales by counterparty (Q1 2005)

Pacific Gas & Electric Company	Energy Sales					
	Trans.	Volume (MWh)	Total Value ($)	Average Price	Max Price	Min Price
AVISTA ENERGY	44	14,975	$710,845.00	$47.47	$56.25	$35.00
BONNEVILLE POWER ADMINISTRATION	55	24,525	$943,475.00	$38.47	$45.00	$30.00
BP ENERGY COMPANY	30	243,030	$10,953,760.00	$45.07	$65.50	$0.00
CALPINE ENERGY SERVICES L.P.	24	17,333	$673,360.00	$38.85	$73.00	$35.00
City and County of San Francisco	6	3,002	$320,098.73	$106.64	$56,400.00	$44.00
CONSTELLATION ENERGY	135	23,172	$995,326.00	$42.95	$64.00	$30.00
DUKE ENERGY TRADING & MARKETING	115	30,261	$1,436,373.00	$47.47	$74.00	$25.00
MIRANT AMERICAS ENERGY MARKETING LP (MAEM)	11	2,030	$77,085.00	$37.97	$55.00	$36.00
PORTLAND GENERAL	49	14,903	$589,346.00	$39.55	$51.00	$30.00
POWEREX CORP	97	41,636	$1,836,498.00	$44.11	$54.00	$0.00
SACRAMENTO MUNICIPAL UTILITY DISTRICT	86	25,475	$1,264,775.00	$49.65	$62.00	$36.50
SAN DIEGO GAS AND ELECTRIC	94	11,385	$520,151.00	$45.69	$62.50	$33.00
SOUTHERN CALIFORNIA EDISON COMPANY	70	13,215	$643,007.50	$48.66	$72.00	$35.00
TURLOCK IRRIGATION DISTRICT	10	4,210	$226,250.00	$53.74	$55.25	$41.50
Western Area Power Administration	3	1,731,118	$30,294,563.98	$17.50	$17.50	$17.50
Total*	**1791**	**2,722,926**	**$76,219,223.96**	**$27.99**	**$56,400.00**	**$0.00**

**includes transactions not listed in table*

Source: FERC EQR Database

It is also interesting to note that, on average, PG&E's energy sales price levels were lower than the price of their purchases. This may be a function of the location of transactions or the timing of the energy bought and sold. Energy on-peak is more valuable than energy off-peak. Similarly, energy bought in Southern California may be priced higher or lower than that in Northern California at a point in time. Each transaction in the FERC EQRs has a delivery location field and a date-time stamp associated with it, and in fact, a descriptive field for peak versus off-peak designation is also attached with each transaction record, so it is possible to get an even more detailed view of the purchases and sales being done by PG&E – in this case the average price for on-peak sales was $52.46/MWh, and the price for off-peak sales was $44.258/MWh for all transactions in Q1 2005.

Figure 10 and Figure 11 present similar summaries for SCE, while Figure 12 and Figure 13 present summaries for SDG&E.

Figure 10. Summary of downloaded SCE energy purchases by counterparty (Q1 2005)

Southern California Edison Company	Energy Purchases*					
	Trans.	Volume (MWh)	Total Value ($)	Average Price	Max Price	Min Price
AES Placerita, Inc.	1	366	$732.00	$2.00	$2.00	$2.00
Calpine Energy Services, L P	109	22,052	$1,214,482.50	$55.07	$75.00	$38.00
Coral Power L.L.C.	67	13,800	$710,146.52	$51.46	$74.00	$0.00
FPL Energy Power Marketing, Inc.	25	30,580	$1,694,812.00	$55.42	$64.50	$51.02
Mirant Americas Energy Marketing LP	17	6,100	$336,105.00	$55.10	$68.00	$38.00
Morgan Stanley Capital Group, Inc.	75	22,866	$1,304,311.00	$57.04	$70.00	$35.00
Occidental Power Services, Inc.	286	275,805	$13,882,832.00	$50.34	$69.00	$44.54
Pacific Gas & Electric	70	13,215	$643,007.50	$48.66	$72.00	$35.00
PPM Energy, Inc.	44	10,284	$600,969.00	$58.44	$66.00	$39.00
San Diego Gas & Electric	8	385	$19,892.50	$51.67	$57.00	$43.00
AES Huntington Beach, LLC	1	55,879	-$113,163.66	-$2.03	-$0.87	-$2.06
Powerex Corp	146	66,675	$3,754,920.00	$56.32	$75.00	$51.75
Total	**849**	**518,007**	**$24,049,046.36**	**$46.43**	**$75.00**	**-$2.06**

**excludes flat-rate transactions*

Source: FERC EQR Database

Comparing SCE's purchase (Figure 10) to its sales (Figure 11) reveals that the firm bought and sold for very similar prices, on average. However, the volume of sales was about seven times the volume of purchases in the quarter.

Figure 11. Sample of SCE energy sales by counterparty (Q1 2005)

Southern California Edison Company	Energy Sales					
	Trans.	Volume (MWh)	Total Value ($)	Average Price	Max Price	Min Price
Arizona Public Service Company	114	87,331	$3,812,657.48	$43.66	$61.00	$0.00
Black Hills Power Inc	1	81	$3,456.65	$42.50	$42.50	$42.50
BP Energy Company	134	292,305	$14,287,909.79	$48.88	$60.00	$32.00
City of Anaheim	11	2,974	$141,782.84	$47.67	$59.00	$40.00
City of Riverside	8	805	$35,734.44	$44.38	$52.00	$35.00
ConocoPhilips Company	101	73,465	$3,444,479.22	$46.89	$75.00	$30.00
Constellation Energy Commodities Group Inc	62	52,739	$2,876,435.37	$54.54	$63.00	$28.00
Coral Power LLC	431	360,386	$19,345,506.83	$53.68	$77.00	$27.00
Duke Energy Marketing America LLC	89	47,489	$1,979,439.47	$41.68	$59.00	$30.00
Dynegy Power Marketing Inc	143	52,300	$2,331,939.28	$44.59	$59.50	$30.00
FPL Energy Power Marketing Inc	15	2,681	$141,185.87	$52.66	$63.75	$47.00
Morgan Stanley Capital Group Inc	315	443,529	$23,457,792.30	$52.89	$70.75	$30.75
Pinnacle West Capital Corporation	1	400	$23,900.00	$59.75	$59.75	$59.75
Powerex Corp	156	88,636	$4,050,826.57	$45.70	$62.00	$15.00
Puget Sound Energy Inc	7	2,820	$124,189.68	$44.04	$54.00	$37.00
San Diego Gas & Electric Company	210	69,182	$2,797,440.01	$40.44	$69.00	$30.00
Seattle City Light Marketing	13	1,540	$59,604.45	$38.69	$45.00	$32.00
Sempra Energy Trading Corp	167	256,790	$13,002,624.49	$50.64	$65.75	$10.00
TransAlta Energy Marketing (US) Inc	238	176,790	$8,688,220.00	$49.14	$63.00	$24.00
UBS AG	55	174,089	$10,221,845.72	$58.72	$77.00	$34.50
Total*	**3808**	**3,546,095**	**$159,917,191.15**	**$45.10**	**$100.00**	**$0.00**

**includes transactions not listed in table*

Source: FERC EQR Database

A cross sectional comparison of all the figures above shows that SDG&E had the lowest trading volume of the three IOUs, with both the least amount of energy purchased, and the least amount of sales.

Figure 12. Summary of downloaded SDG&E energy purchases by counterparty (Q1 2005)

San Diego Gas & Electric Company	Energy Purchases					
	Trans.	Volume (MWh)	Total Value ($)	Average Price	Max Price	Min Price
AES Delano, Inc.	3	69,289	$2,771,546.56	$40.00	$40.00	$40.00
Calpine Energy Services, L P	100	21,516	$1,128,871.00	$52.47	$70.00	$40.00
Coral Power L.L.C.	70	8,842	$472,617.61	$53.45	$75.50	$0.00
FPL Energy Power Marketing, Inc.	3	860	$47,160.00	$54.84	$61.00	$53.75
Mirant Americas Energy Marketing LP	86	11,238	$493,231.00	$43.89	$59.50	$34.75
Morgan Stanley Capital Group, Inc.	1248	49,960	$2,311,351.50	$46.26	$71.00	$33.00
Mountain View Power Partners III, LLC	116	11,574	$568,862.10	$49.15	$49.15	$49.15
Occidental Power Services, Inc.	11	4,580	$212,870.00	$46.48	$64.00	$34.25
Pacific Gas & Electric	94	11,385	$520,151.00	$45.69	$62.50	$33.00
Phoenix Wind Power LLC	98	1,241	$18,087.20	$14.57	$49.15	$0.00
Powerex Corp	141	31,720	$1,720,416.25	$54.24	$70.00	$37.25
PPM Energy, Inc.	1	18,289	$855,100.00	$46.75	$68.00	$0.00
Total	**1971**	**240,494**	**$11,120,264.22**	**$46.24**	**$75.50**	**$0.00**

Source: FERC EQR Database

Figure 13. Sample of SDG&E's energy sales by counterparty (Q1 2005)

San Diego Gas & Electric Company	Energy Sales					
	Trans.	Volume (MWh)	Total Value ($)	Average Price	Max Price	Min Price
Avista Energy	1	7,400	$338,800.00	$45.78	$52.00	$40.50
Bonneville Power Administration	2	995	$34,240.00	$34.41	$35.00	$32.00
BP Energy Company	18	5,200	$258,300.00	$49.67	$56.50	$39.75
California Department of Water Resources	42	7,941	$379,271.50	$47.76	$66.00	$38.00
Calpine Energy Services	34	9,888	$513,662.00	$51.95	$57.00	$35.00
City of Anaheim	1	5	$245.00	$49.00	$49.00	$49.00
City of Escondido	3	7	$627.36	$96.52	$98.88	$93.54
Constellation Energy Commodities Group Inc	75	1,308	$66,923.50	$51.16	$61.50	$36.75
Coral Power LLC	70	11,074	$523,406.25	$47.26	$68.00	$35.00
Dynegy Power Marketing Inc	75	23,998	$1,196,950.00	$49.88	$64.00	$33.00
Morgan Stanley Capital Group Inc	92	20,262	$919,004.50	$45.36	$60.00	$36.50
Pacific Gas & Electric Company	14	1,181	$63,663.00	$53.91	$61.00	$33.00
PacifiCorp	26	6,960	$323,660.00	$46.50	$55.50	$39.75
Portalnd General Electric Company	6	1,238	$46,588.00	$37.63	$51.75	$28.00
Portland General Electric Company	25	6,500	$300,336.00	$46.21	$54.00	$30.00
Powerex Corporation	14	4,770	$194,080.00	$40.69	$52.00	$36.00
PPM Energy Inc	41	6,773	$325,363.00	$48.04	$56.25	$37.00
Sacramento Municipal Utility District	31	7,195	$319,475.00	$44.40	$50.00	$37.50
Salt River Project	1	40	$800.00	$20.00	$20.00	$20.00
Southern Salifornia Edison Company	1	45	$1,935.00	$43.00	$43.00	$43.00
Turlock Irrigation District	4	1,200	$53,300.00	$44.42	$48.25	$36.75
Total*	**699**	**138,885**	**$6,564,283.61**	**$47.26**	**$98.88**	**$0.00**

**includes transactions not listed in table*

Source: FERC EQR Database

Many comparisons are possible between IOUs. As can be seen from the tables above, the average sales prices were similar for SCE ($46.25/MWh) and for SDG&E ($46.24/MWh), but significantly lower for PG&E ($38.50/MWh). Why was this? Perhaps it was a difference in the length of contracts under which the transactions took place – PG&E purchased energy only under short-term contracts in the first quarter of 2005. The FERC EQR database would allow investigation of many other possibilities.

In their appeal, PG&E suggested that quarterly aggregated summary tables are too detailed. However, the detail of the FERC EQR database far exceeds that which is proposed to be included in the aggregated summary tables. Indeed, the range of analyses that could be performed with the FERC EQR data exceeds that which could be done with the aggregated summary tables. As described above, each FERC EQR transaction is time stamped, with the smallest increment smaller than an hour. The price and quantity information is available. Thus, data could be segmented to relate IOU purchases and sales to market fundamentals (such as fuel prices and weather) on a very precise basis.

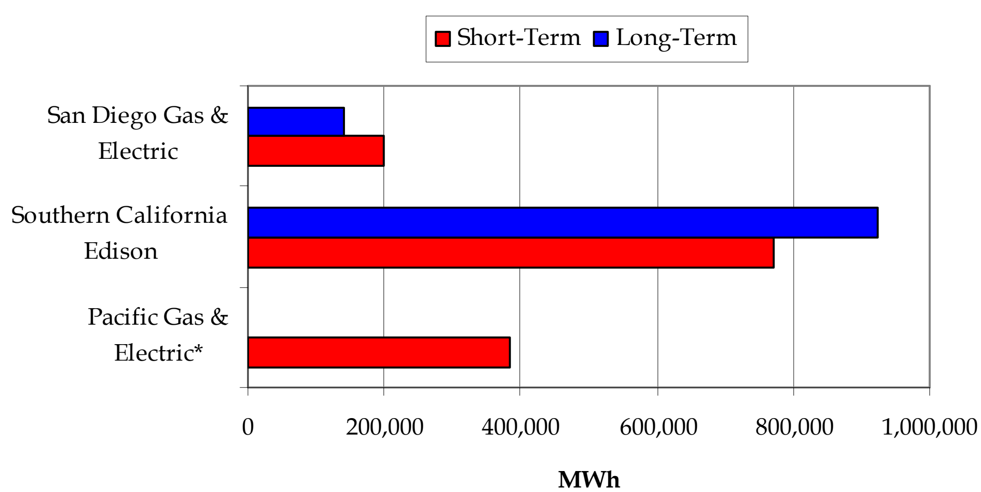
Similarly, it would be possible to use the data going back to 2002 to create a very detailed analysis of the drivers behind IOU transactions. Statistical techniques could be applied to the transactions data to evaluate the IOUs willingness to purchase (sell) at particular prices, and how that willingness is related to wider market conditions, such as seasonal supply-demand conditions, conditions in fuel markets, and hydrology. The FERC EQR data could be overlayed with detailed hourly demand data filed with FERC, supply cost information and production data, and hourly market prices for imbalance energy from the CAISO.

The statistical models that could be created by the FERC EQR data could then be used to evaluate a variety of procurement-related issues and possible future trading strategies of the IOUs, including:

- analysis of IOUs' price responsiveness to changing input costs (fuel prices);
- arbitrage strategies of the IOUs between CAISO's imbalance market and bilateral purchases;
- IOUs' preference (if any) for particular counterparties;
- the price sensitivity of the IOUs during specific time periods and seasons, especially as that relates to demand and hydrology; and
- possible product preference by the IOUs when purchasing and selling.

Contract terms, especially information pertaining to transactions from long-term contracts, could also be used to develop an understanding of the IOUs' trading strategies. For example, during Q1 2005, the three IOUs had made purchases of energy totaling just over 1,000 GWh under long-term designations, versus about 1,355 GWh under short-term designations. Figure 14 shows the breakdown of short term and long term purchases, by IOU.

Figure 14. Q1 2005 energy purchases by IOUs



*PG&E made no purchases designated as long-term in the first quarter of 2005.

Source: FERC EQR Database

Although the preceding analysis is focused on energy transactions, the FERC EQR database also provides the opportunity to gain other data about the IOUs.

One area of investigation could be to analyze the long-term obligations of the IOUs. One could examine the contract's start and expiration dates to see the length of the obligations. An analyst could combine common public releases about a complete RFO, i.e. the winners and the total amounts awarded, with FERC EQR contract and transaction data to estimate the price and other terms of the contracts awarded to each winner.

Moreover, by combining public information about generating capacity owned by an IOU, historical load data, and historical FERC EQR data, an analyst could estimate the amount of load that the IOU is covering under current and historical commitments. The analysis could then be extended to assess the duration of current commitments and the pricing for the various long term contracts.

5 Conclusions

In their filings and testimonies, the IOUs have suggested that the release of the aggregate summary tables to the public would allow access to proprietary and confidential data, and provide potential suppliers with information that is otherwise neither available nor attainable. The IOUs then argue that the suppliers would then collude and raise the price at which they are willing to supply the IOUs and thus cause high procurement costs and damage ratepayers. However, this plotline is not realistic. Similar information to that which is proposed to be included in the aggregated summary tables is already available in the public domain; for example, historical transaction data from the FERC EQRs. Indeed, the fact that this information is both actual data (not projected), and more detailed (i.e. hour, price, location, and company-specific), means that a great deal more about the IOUs' procurement needs could be ascertained from this publicly available data than from the aggregated summary tables.

If the FERC EQR data is so comprehensive, why is there a need to release aggregated summary tables? The FERC EQR database is an excellent resource of competitive information about the power sector; however it requires a certain level of sophistication. The full database, which would be necessary for a comprehensive analysis, is very large (20 gigabytes currently) and expanding. It will continue to grow with each set of quarterly filings. Because the database is too massive to be housed on a standard computer, a firm would require a significant investment in information technology infrastructure (hardware and software) to allow it to make efficient use of the full data set. To use the database effectively, a firm would also need to devote significant resources to learning the peculiarities of the dataset, standardizing it, and correcting or accounting for occasional data entry mistakes, and updating the data as new filings become available, as well as updating the various analytical tools and models which are derived off that data. This is a very time consuming and relatively costly process.

Although the information in the FERC EQR database can provide a much more detailed perspective on IOUs' net short position and price sensitivity, it may be difficult (and expensive) for some market participants to fully understand. Thus, the release of information embodied in the aggregate summary tables can act as a substitute to the information that could otherwise be developed by sophisticated market participants using the FERC EQR data. Less sophisticated players in the market could more readily understand and use the information in the aggregated summary tables to make investment decisions, such as a commitment to develop a new generation project. The aggregated summary tables would also provide important information on future needs ahead of the formal procurement processes that the IOUs undergo (through Requests for Offers) in order to allow potential suppliers to prepare to submit credible offers to the IOUs.

On that basis, I would expect that the aggregated summary tables would not cause harm, but would foster a more aggressive competitive environment in procurement because they would invite less sophisticated market participants and potential new investors to the "playing field" by providing transparency on the future needs of the IOUs. This is going to benefit – not harm - ratepayers.

6 Appendix: Sample FERC EQR excerpts for each IOU

The tables presented in Figure 15, Figure 16, and Figure 17 present samples of data taken from the FERC EQR database. The records presented are truncated and do not represent all fields available for each entry, and are intended only to provide an illustration of the data available.

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Figure 15. Sample FERC EQR Extract for PG&E

Purchase Transactions

respondent name	customer name	transaction begin date	transaction end date	delivery control area	class name	term name	increment peaking	product name	transaction quantity	price	units
Calpine Energy Services, L P	Pacific Gas & Electric Co.	01/01/2005 12:00:00 AM	01/31/2005 12:00:00 AM	CISO	F	ST	P	CAPACITY	40	25000	$/KW-MO
Calpine Energy Services, L P	Pacific Gas & Electric Co.	01/01/2005 12:00:00 AM	01/31/2005 12:00:00 AM	CISO	F	ST	P	CAPACITY	70	25000	$/KW-MO
Calpine Energy Services, L P	Pacific Gas & Electric Co.	01/01/2005 12:00:00 AM	04/01/2005 12:00:00 AM	CISO	F	ST	P	ENERGY	97501	17.12	$/MWH
Calpine Energy Services, L P	Pacific Gas & Electric Co.	01/01/2005 12:00:00 AM	04/01/2005 12:00:00 AM	CISO	F	ST	P	ENERGY	67160	17.12	$/MWH
Powerex Corp	Pacific Gas & Electric Co.	01/01/2005 10:00:00 AM	01/01/2005 09:59:00 PM	CISO	F	ST	OP	ENERGY	1800	70.5	$/MWH
Mirant Americas Energy Mrktg.	Pacific Gas & Electric Co.	01/01/2005 10:00:00 AM	01/01/2005 09:59:00 PM	CISO	F	N/A	P	ENERGY	600	68.25	$/MWH
Powerex Corp	Pacific Gas & Electric Co.	01/01/2005 05:00:00 PM	01/01/2005 05:59:00 PM	CISO	F	ST	OP	ENERGY	100	59	$/MWH
Calpine Energy Services, L P	Pacific Gas & Electric Co.	01/01/2005 10:00:00 PM	01/01/2005 11:00:00 PM	CISO	F	ST	P	ENERGY	31	48	$/MWH

Purchase Contracts

respondent name	customer company name	contract commencement date	contract termination date	class name	term name	increment peaking	product name	quantity	units for contract	rate	rate description
Calpine Energy Services, L P	Pacific Gas & Electric Co.	01/01/2004	12/31/2007	N/A	LT	N/A	CAPACITY	0		0	N/A
Mirant Americas Energy Mrktg.	Pacific Gas & Electric Co.	10/12/2000	12/31/2005	N/A	N/A	N/A	ENERGY	0		0	market-based
Powerex Corp	Pacific Gas & Electric Co.	01/24/2003	/ /	N/A	N/A	N/A	ENERGY	0	MW	0	Market Based

Sales Transactions

respondent name	customer name	transaction begin date	transaction end date	delivery control area	class name	term name	increment peaking	product name	transaction quantity	price	units
Pacific Gas & Electric Co.	Bay Area Rapid Transit (BART)	01/01/2005 12:00:00 AM	01/31/2005 12:24:00 AM	CISO	F	LT	FP	REG. & FREQ.	71215	0.04	$/KW-MO
Pacific Gas & Electric Co.	Bay Area Rapid Transit (BART)	01/01/2005 12:00:00 AM	01/31/2005 12:24:00 AM	CISO	F	LT	FP	ENG. IMBL.	143416	0.1	$/KWH
Pacific Gas & Electric Co.	Bay Area Rapid Transit (BART)	01/01/2005 12:00:00 AM	01/31/2005 12:24:00 AM	CISO	F	LT	FP	SUPPL. RES.	71215	0.2145	$/KW-MO
Pacific Gas & Electric Co.	Western Area Power Admn.	01/01/2005 12:00:00 AM	01/31/2005 12:24:00 AM	CISO	F	LT	FP	CAPACITY	255000	6.705	$/KW-MO
Pacific Gas & Electric Co.	Western Area Power Admn.	01/01/2005 12:00:00 AM	01/31/2005 12:24:00 AM	CISO	F	LT	FP	CAPACITY	5247	7.711	$/KW-MO
Pacific Gas & Electric Co.	City & County of San Francisco	01/01/2005 12:00:00 AM	01/31/2005 12:24:00 AM	CISO	F	LT	FP	CAPACITY	40300	4.225	$/KW-MO
Pacific Gas & Electric Co.	BONNEVILLE POWER ADMN.	01/01/2005 01:00:00 AM	01/01/2005 11:59:00 PM	HUB	N/A	ST	N/A	ENERGY	1750	35	$/MWH
Pacific Gas & Electric Co.	CALPINE ENERGY SERVICES	01/01/2005 01:00:00 AM	01/01/2005 11:59:00 PM	CISO	N/A	ST	FP	ENERGY	2475	36	$/MWH

Sales Contracts

respondent name	customer company name	contract commencement date	contract termination date	class name	term name	increment peaking	product name	quantity	units for contract	rate	rate description
Pacific Gas & Electric Co.	City & County of San Francisco	12/21/1987	01/07/2015	F	LT	N/A	CAPACITY	19164	KW	5	Settlement Rat
Pacific Gas & Electric Co.	Western Area Power Admn.	07/31/1967	01/01/2005	F	LT	N/A	GRNDFTRD.	11400	KW	2.101	Rate Schedule
Pacific Gas & Electric Co.	Western Area Power Admn.	07/31/1967	01/01/2005	F	LT	N/A	CAPACITY	255000	KW	6.298	Settlement Rat
Pacific Gas & Electric Co.	Western Area Power Admn.	07/31/1967	01/01/2005	F	LT	N/A	ENERGY	0	KWH	0.0202	Settlement Rat
Pacific Gas & Electric Co.	Bay Area Rapid Transit (BART)	05/11/1998	10/01/2016	N/A	LT	FP	REACTIVE	65000	KW	0.205	Cost Based. R
Pacific Gas & Electric Co.	Bay Area Rapid Transit (BART)	05/11/1998	10/01/2016	N/A	LT	FP	SPINNING	65000	KW	0.2163	Cost Based. R
Pacific Gas & Electric Co.	BONNEVILLE POWER ADMN.	08/16/1991	12/31/2049	N/A	ST	N/A	ENERGY	0		0	Market based
Pacific Gas & Electric Co.	CALPINE ENERGY SERVICES	02/18/2003	12/31/2049	N/A	ST	N/A	ENERGY	0		0	Market based

Figure 16. Sample FERC EQR Extract for SCE

Purchase Transactions

respondent name	customer name	transaction begin date	transaction end date	delivery control area	class name	term name	increment peaking	product name	transaction quantity	price	units
AES Placerita, Inc.	Southern California Edison Co.	01/01/2005 12:00:00 AM	03/31/2005 11:59:59 PM	CISO	F	LT	P	OTHER	1	11167	FLAT RATE
Harbor Cogeneration Co.	Southern California Edison Co.	01/01/2005 12:00:00 AM	01/31/2005 12:00:00 AM	CISO	UP	LT	FP	OTHER	0	1500	FLAT RATE
Reliant Energy Etiwanda, Inc.	Southern California Edison Co.	01/01/2005 12:00:00 AM	01/31/2005 11:59:00 PM	CISO	N/A	N/A	N/A	CAPACITY	640	4509.8354	FLAT RATE
Coral Power L.L.C.	Southern California Edison Co.	01/01/2005 01:00:00 AM	01/02/2005 12:59:00 AM	CISO	F	ST	FP	BKD. OUT	59.76	0.0001	$/MWH
Pacific Gas & Electric	Southern California Edison Co.	01/01/2005 01:00:00 AM	01/01/2005 11:59:00 PM	CISO	N/A	ST	N/A	ENERGY	100	54	$/MWH
Calpine Energy Services, L P	Southern California Edison Co.	01/02/2005 08:00:00 PM	01/02/2005 10:00:00 PM	CISO	F	ST	P	ENERGY	178	60	$/MWH
Occidental Power Services, Inc.	Southern California Edison Co.	01/03/2005 06:00:00 AM	01/03/2005 10:00:00 PM	CISO	F	ST	P	ENERGY	1600	47.685	$/MWH
FPL Energy Power Marketing	Southern California Edison Co.	01/03/2005 06:00:00 AM	01/03/2005 09:00:00 PM	CISO	F	ST	P	ENERGY	1600	54.35	$/MWH

Purchase Contracts

respondent name	customer company name	contract commencement date	contract termination date	class name	term name	increment peaking	product name	quantity	units for contract	rate	rate description
Harbor Cogeneration Co.	Southern California Edison Co.	06/01/2003	10/31/2007	N/A	LT	FP	OTHER	0	MWH	3.83	Tolling
Calpine Energy Services, L P	Southern California Edison Co.	01/03/2003	/ /	N/A	LT	N/A	ENERGY	0		0	N/A
Occidental Power Services, Inc.	Southern California Edison Co.	07/01/2003	/ /	N/A	N/A	N/A	ENERGY	0	MWH	0	N/A

Sales Transactions

respondent name	customer name	transaction begin date	transaction end date	delivery control area	class name	term name	increment peaking	product name	transaction quantity	price	units
Southern California Edison Co.	Met. Water Dist. of S. California	01/01/2005 01:00:00 AM	01/31/2005 11:59:00 PM	HUB	F	LT	N/A	ENERGY	43995	0	$/MWH
Southern California Edison Co.	Williams Power Company Inc	01/01/2005 01:00:00 AM	01/01/2005 11:59:00 PM	HUB	F	ST	OP	ENERGY	448.3005	44.25	$/MWH
Southern California Edison Co.	Mirant Americas Energy Mktng.	01/01/2005 01:00:00 AM	01/01/2005 11:59:00 PM	HUB	F	ST	OP	ENERGY	251.0483	44.25	$/MWH
Southern California Edison Co.	BP Energy Company	01/01/2005 01:00:00 AM	01/31/2005 11:59:00 PM	HUB	F	ST	OP	ENERGY	12584.093	48	$/MWH
Southern California Edison Co.	Salt River Project	01/01/2005 01:00:00 AM	01/01/2005 11:59:00 PM	HUB	N/A	ST	OP	ENERGY	4800	38.5	$/MWH
Southern California Edison Co.	Duke Energy Trading & Mrktg.	01/01/2005 01:00:00 AM	01/01/2005 11:59:00 PM	HUB	F	ST	OP	ENERGY	448.3005	44.25	$/MWH
Southern California Edison Co.	Powerex Corp	01/01/2005 01:00:00 AM	01/01/2005 07:59:00 AM	HUB	F	ST	N/A	ENERGY	604.878	32	$/MWH
Southern California Edison Co.	Sempra Energy Trading Corp	01/01/2005 01:00:00 AM	01/01/2005 11:59:00 PM	HUB	F	ST	OP	ENERGY	896.601	39	$/MWH

Sales Contracts

respondent name	customer company name	contract commencement date	contract termination date	class name	term name	increment peaking	product name	quantity	units for contract	rate	rate description
Southern California Edison Co.	Met. Water Dist. of S. California	05/21/2001	/ /	N/A	LT	FP	INTRCNCT.	39.6	MW	0	No Billing
Southern California Edison Co.	Duke Energy Trading & Mrktg.	01/02/2003	/ /	NF	ST	N/A	ENERGY	0	MW	0	market-based
Southern California Edison Co.	Powerex Corp	01/02/2003	/ /	F	ST	N/A	ENERGY	0	MW	0	market-based

Figure 17. Sample FERC EQR Extract for San Diego Gas & Electric

Purchase Transactions

respondent name	customer name	transaction begin date	transaction end date	delivery control area	class name	term name	increment peaking	product name	transaction quantity	price	units
AES Delano, Inc.	San Diego Gas & Electric Co.	01/01/2005 12:00:00 AM	01/31/2005 12:00:00 AM	CISO	F	LT	N/A	CAPACITY	21671.581	13.7	FLAT RATE
Morgan Stanley Capital Group	San Diego Gas & Electric Co.	01/01/2005 12:00:00 AM	01/01/2005 12:59:00 AM	CISO	F	ST	N/A	ENERGY	25	44.25	$/MWH
Mountain View Power Partners	San Diego Gas & Electric Co.	01/01/2005 12:00:00 AM	01/01/2005 08:00:00 AM	CISO	F	N/A	N/A	ENERGY	44	49.15	$/MWH
Phoenix Wind Power LLC	San Diego Gas & Electric Co.	01/01/2005 01:00:00 AM	01/01/2005 07:00:00 AM	CISO	F	LT	N/A	ENERGY	6	49.15	$/MWH
Pacific Gas & Electric	San Diego Gas & Electric Co.	01/01/2005 01:00:00 AM	01/01/2005 11:59:00 PM	CISO	N/A	ST	N/A	ENERGY	100	56	$/MWH
Coral Power L.L.C.	San Diego Gas & Electric Co.	01/01/2005 07:00:00 AM	01/01/2005 10:59:00 PM	CISO	N/A	ST	FP	BKD. OUT	800	51	$/MWH
Calpine Energy Services, L P	San Diego Gas & Electric Co.	01/01/2005 07:00:00 AM	01/01/2005 11:00:00 PM	CISO	F	ST	P	ENERGY	800	54	$/MWH
Morgan Stanley Capital Group	San Diego Gas & Electric Co.	01/01/2005 07:00:00 AM	01/01/2005 07:59:00 AM	CISO	F	ST	N/A	ENERGY	25	44.25	$/MWH

Purchase Contracts

respondent name	customer company name	contract commencement date	contract termination date	class name	term name	increment peaking	product name	quantity	units for contract	rate	rate description
Mountain View Power Partners III,	San Diego Gas & Electric Co.	12/06/2003	12/31/2018	F	LT	N/A	ENERGY	0	MWH	0	Market Based
Phoenix Wind Power LLC	San Diego Gas & Electric Co.	12/20/2003	12/30/2018	F	LT	N/A	ENERGY	0	MWH	0	Market Based
Morgan Stanley Capital Group	San Diego Gas & Electric Co.	01/01/2000	/ /	N/A	N/A	N/A	ENERGY	0		0	Market Based

Sales Transactions

respondent name	customer name	transaction begin date	transaction end date	delivery control area	class name	term name	increment peaking	product name	transaction quantity	price	units
San Diego Gas & Electric Co.	Southern California Edison	01/01/2005 01:00:00 AM	01/31/2005 11:59:00 PM	CISO	N/A	N/A	N/A	ENERGY	18	0	$/MWH
San Diego Gas & Electric Co.	Imperial Irrigation District	01/01/2005 01:00:00 AM	01/31/2005 11:59:00 PM	IID	N/A	N/A	N/A	ENERGY	16.1	0	$/MWH
San Diego Gas & Electric Co.	Calpine Energy Services	01/01/2005 01:00:00 PM	01/01/2005 05:00:00 PM	HUB	F	ST	OP	ENERGY	100	43	$/MWH
San Diego Gas & Electric Co.	PPM Energy Inc	01/01/2005 03:00:00 PM	01/01/2005 05:00:00 PM	HUB	F	ST	OP	ENERGY	75	44	$/MWH
San Diego Gas & Electric Co.	PacifiCorp	01/02/2005 01:00:00 AM	01/02/2005 11:59:00 PM	HUB	F	ST	FP	ENERGY	600	44.5	$/MWH
San Diego Gas & Electric Co.	Morgan Stanley Capital Group	01/04/2005 01:00:00 AM	01/04/2005 11:59:00 PM	HUB	F	ST	OP	ENERGY	200	46	$/MWH
San Diego Gas & Electric Co.	Powerex Corporation	01/04/2005 01:00:00 AM	01/04/2005 11:59:00 PM	HUB	F	ST	OP	ENERGY	200	43.75	$/MWH
San Diego Gas & Electric Co.	Cal. Dept. of Water Resources	01/04/2005 07:00:00 AM	01/04/2005 08:00:00 AM	HUB	F	ST	P	ENERGY	100	50	$/MWH

Sales Contracts

respondent name	customer company name	contract commencement date	contract termination date	class name	term name	increment peaking	product name	quantity	units for contract	rate	rate description
San Diego Gas & Electric Co.	Cal. Dept. of Water Resources	02/01/2004	/ /	F	ST	OP	ENERGY	70	MWH	0	market based
San Diego Gas & Electric Co.	Calpine Energy Services	02/01/2004	/ /	F	ST	OP	ENERGY	200	MWH	0	market based
San Diego Gas & Electric Co.	Morgan Stanley Capital Group	02/01/2004	/ /	F	ST	OP	ENERGY	200	MWH	0	market based

Attachment F

***Availability Of Market Price Information For The Wholesale Electricity Market In The Western Electricity Coordinating Council*,**
Prepared By Julia Frayer, London Economics.

Availability of market price information for wholesale electricity markets in the Western Electricity Coordinating Council (WECC)

prepared by London Economics International LLC for the California Energy Commission

August 12, 2005

1 Introduction

The IOUs in their testimony argue that the data proposed to be released in the Notice of Intent ("NOI") would provide important new information about the willingness to pay of the IOUs. Pacific Gas & Electric Company's ("PG&E") witness, Roy Kuga, believes that the aggregated summary table will somehow proffer an "unfair advantage in the pricing of the last increment."[1] However, their arguments and evidence ignore the fact that robust price indicators are readily available.[2] The summary aggregated tables, as proposed by the NOI, will not provide wholly new information about willingness to pay; rather, they will improve market participants' understanding of the fundamentals driving already existing price signals for future energy transactions.

There is no centralized exchange in California or in Western Electricity Coordinating Council ("WECC") that provides a marketplace for day-ahead electricity trading. However, there is a liquid market for bilateral transactions in the region, and price indicators for future transactions are published by several different information providers. As mentioned in the CEC testimony filed on July 8th 2005, there are numerous sources for future wholesale electricity price indicators in California and the broader WECC region. In this rebuttal testimony, I provide an overview of this publicly available data on future market prices, describe how this information is collected, and also provide a snapshot of the data available for various pricing hubs in the WECC as an illustration of this data's availability.

1 *See* Kuga at 2.

2 In fact, as stated in my initial testimony, Dr. Charles Plott, witness to Southern California Edison Company (SCE), assumes in his experiment that there is *no* "public transaction price information"; apparently Dr. Plott assumes that the availability of public transaction price information would inevitably change the outcomes observed in his experiments by providing some additional knowledge of trading conditions. (*See* Plott's Exhibit A at page 4.) In fact, in the current California market, there is a wealth of price information, both historical and forward looking. In this paper, I discuss forward-looking price information, while Attachment E entitled *Guide to the FERC Electric Quarterly Reports* lays out the wealth of historical transaction and contract-level data available from the Federal Energy Regulatory Commission in their Electronic Quarterly Reporting ("EQR") system.

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Boston, MA 02111
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2 Publishing of bilateral price data

Bilateral transactions are defined by decentralized trades between buyers and sellers, rather than a single auction process which is defined by a centralized exchange. In WECC today, bilateral transactions for energy may involve some sales/purchases negotiated between the seller/buyer on a dedicated, one-on-one basis or through more formal Requests for Proposals ("RFPs") and Request for Offers ("RFOs"). Alternatively, some market participants arrange their transactions through brokers, dealers, and over-the-counter ("OTC") electronic exchanges. Bilateral transactions do not need to conform to a uniform set of trading arrangements. Some transactions may be a full requirements "package" involving the sale/purchase of energy, capacity, and some ancillary services. Other transactions may be energy sales only. Some transactions will be settled on the basis of adjusted or variable price indices, while others will be fixed-price.

In spite of the diversity and decentralized nature of the bilateral market segment for power, there are a number of sources for robust price indications of the next-day bilateral physical market, as well as longer-term forward transactions. For example, some third-party data providers (such as *Platts*[3]) serve as a clearinghouse for contract data from power marketers and traders, which they process and publish in the form of a daily price index. There are also other OTC trading platforms which distribute day-ahead price indicators free of charge; for example, the IntercontinentalExchange, Inc. ("ICE") publishes a daily index price indicator for most major trading hubs in North America. Indeed, transparent exchanges such as ICE are one of the procurement methods that California IOUs are authorized by the California Public Utility Commission ("CPUC") in Order D.03-12-062 to pursue for energy procurement. Another source for data is brokerage firms (such as Amerex), which may disclose last settled price, as well as publish the current bid/ask spreads of forward transactions for various durations (tenures), including balance of day, week, month, quarter and calendar year.

In addition, there are regulatory controls on the provision of such data, which underline its reliability. Following the California electricity crisis, FERC established certain regulations and codified standards[4] in order to improve the reliability of such data. These guidelines state that prices should be provided by individuals "separate from trading activities". Due to these improvements, third-party price indices have become more robust over the last few years and more widely accepted. In addition, The Electricity Modernization Act of 2005 recently passed by the U.S. Congress and signed into law by the President, includes a mandate for improved information transparency, which could potentially involve a government mandated price reporting system in the future.[5] Industry groups had voiced opposition to this clause because

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3 *Platts*, a subsidiary of the McGraw-Hill Companies, provides energy information such as independent industry news and price benchmarks. *Platts* covers the oil, natural gas, electricity, nuclear power, coal, petrochemical and metals markets. See www.platts.com

4 *Policy Statement on Natural Gas and Electric Price Indices,* FERC, ¶PL3-03-000 (July 24th 2003).

5 Section 1280 of the Electricity Modernization Act states that the FERC is directed to facilitate price transparency in the interstate sale of electricity to protect consumers and prevent market manipulation. FERC is authorized to disseminate information about the availability of and price of electricity to all market participants. This information may come from existing data providers or from an electronic information system if FERC determines that existing sources are not sufficiently transparent or accurate.

"the truly unique cooperative industry and government price reporting system (that) has been developed over the last three years" has helped to "restore confidence in wholesale prices, as well as to increase transparency and liquidity."[6] As noted by industry participants, participation in such surveys has increased dramatically – "over 400%" in the last three years alone.[7]

2.1 *Platts*

Platts obtains its price data through its daily, confidential surveys of market participants. Through these surveys, *Platts* asks market participants to report all fixed-price physical and financial deals for delivery across key trading points in North America for each business day (and for longer time periods for its long-term assessment). The reporting of the data is consistent with FERC's standards which state that prices should be provided by individuals "separate from trading activities".[8] Thus, daily reports are typically sent to *Platts* by a non-commercial department of the company, such as accounting or bookkeeping staff. Based on these daily reports, *Platts*' editors produce indices and assessments of the next-day trading (day-ahead prices).

***Platts* currently publishes 30 daily on-peak and 26 daily off-peak next day price indices for North America in its *Megawatt Daily* publication**

- index price ($/MWh)
- price change from previous day ($/MWh)
- high price ($/MWh)
- low price ($/MWh)
- volume (MW)
- number of transactions underlying the index price

For the trading hubs where there is sufficient liquidity, *Platts* uses volume-weighted averages to calculate the index value. Prior to calculating the index, the transactional data is scrutinized for potential mistakes made by the data provider and for outliers.[9] The data is also "weeded out" for non-standard-size deals. In a liquid market, non-standard-size deals are automatically excluded from the index calculation. However, special consideration is often given to odd-sized deals that can affect price.

2.2 Amerex

Amerex is a leading broker of physical electricity sales, uniting buyers and sellers in power markets across North America. The brokerage service was started in 1996 and currently transacts over 4,000 GWh of energy daily across North America, with the bulk of these transactions in physical power.[10]

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6 *Megawatt Daily*, July 20, 2005.

7 Id.

8 See FERC's July 2003 *Policy Statement on Natural Gas and Electric Price Indices*.

9 Outliers are defined by *Platts* as deals more than two standard deviations from the mean or deals submitted that are outside of what *Platts* has seen as the range of trading for that particular day.

10 See http://www.amerexenergy.com/electrical_power.aspx

As a service to its members, Amerex distributes a pricing sheet daily at close of trading which highlights price ranges (bid/ask spreads in absolute dollar levels per MWh and heat rate terms using NYMEX natural gas prices) for various tenures and delivery points. Amerex supplies pricing information on all the major North American power hubs and lists forward prices out for the next ten years, providing a unique insight to how market participants view likely supply-demand dynamics going forward.

***Amerex* currently publishes bid/ask spreads for the following time periods and tenures:**

- Peak (5x16 weekdays)
- Off-peak/wrap (5x8 on weekdays and 2x24 on weekends)
- Around-the-clock (7x24)
- Balance of month,
- Monthly / seasonal /quarterly,
- Calendar year 2006-2015

2.3 InterContinentalExchange (ICE)

IntercontinentalExchange (ICE) operates the leading electronic global futures and OTC marketplaces for trading a broad array of energy commodity contracts. ICE provides a single integrated electronic platform for real-time, direct price discovery and risk management. The ICE platform is accessed daily by thousands of traders and trading operations professionals to trade hundreds of commodity and derivative contracts including crude oil and refined products, natural gas, power and precious metals. ICE largely provides day-ahead trades. While it does see some forward transactions, these are largely within a one month time frame with relatively low liquidity for the WECC region.

An ICE affiliate, the 10x Group, delivers transparent energy market information directly from the ICE trading platform. Market data services from ICE and its affiliates include daily natural gas and power indices, mark-to-market pricing, and real-time OTC and futures prices. 10x relies upon efficient and secure technology to generate indices based solely upon auditable transaction data.

2.4 Dow Jones

Dow Jones Indexes is an independent, full-service index provider that develops, maintains, and licenses more than 3,000 market indices for investment products. Dow Jones has indices for a variety of financial products, including exchange-traded funds, futures and options contracts, mutual funds, variable annuity and equity-indexed annuities, and structured products such as OTC options, swaps, warrants, equity-linked notes, and public/private debt.[11]

As part of its wider financial market services, Dow Jones tracks day ahead electricity prices for most major hubs in North America, including those in WECC. The Dow Jones Electricity Price Indexes are volume-weighted averages of specifically defined bilateral, wholesale, physical transactions. Index participants provide Dow Jones with their itemized bilateral transactions and volume for eligible electricity products sold at specific delivery points, as well as with any purchases made from entities not contributing to the indexes. Participants are asked to provide

11 Dow Jones Indexes, see http://www.djindexes.com/mdsidx/index.cfm?event=showAboutUsOverview

Dow Jones with daily index data by 10 a.m. Pacific Time on the power flow date for WECC prices.

3 Example of available future pricing information in the WECC region

In this section, I provide wholesale electricity price indications for July 18, 2005 for a variety of pricing hubs in WECC, including three major hubs in California – SP15 (the zone covering Southern California), NP15 (the zone covering Northern California), and COB (the zone covering the California Oregon Border) - as well as three hubs in the broader WECC – Palo Verde (in Arizona State), Mid-C (in Washington State), and Mead (in Southern Nevada).

All data was obtained from the commercial entities that collect and provide this information. Where not explicitly noted, prices are for on-peak contracts.[12] Prices vary slightly according to the different information providers as a result of how each collects, cleans, and tabulates the data. A comparison of several different indices can be used as a way to develop a more confident and comprehensive view of market pricing.

Based on a snapshot of the data on July 18, 2005 from a number of reporting entities, prices increase slightly through quarter 1 of 2006, rise again in late 2006, and then follow a longer-term declining trajectory. The mid-2006 dip in prices is consistent with fundamentals, as it relates to the annual peak in must-take hydro in California in the springtime. The similarity in price outlooks across data providers underscores the robustness of such information and its applicability as a key source of strategic information about future prices in a given market. The trends are consistent not only among data providers for a given trading hub but also among the various WECC trading hubs. For example, all six hubs see a dip in power prices in the middle of 2006. As an indicator of the consistency of the price signal among independent sources, I calculated the percent deviation of the price points[13] for the day-ahead products and found that the average percent deviation of the prices was 0.7%, with the lowest deviation at 0.2% and the highest at 1.5%. By any measure, these price points are clearly consistent and reliable.

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12 *Platts*: Peak= Mon-Sat HE 0700 – HE 2200, west markets traded as a Monday off-peak and all day Sunday package, *Amerex*: Peak= Mon-Sun HE 0700 – 2200; Off-peak Hours= Mon-Sun HE 2300 – 0600, *ICE*: Peak= Mon-Sat HE 0700 – HE 2200 excluding NERC holidays; Off Peak= Mon-Sat HE 2300 – HE 2400; HE 0100 - HE 0600; Sunday HE 0100 – HE 2400 including NERC Holidays, *Dow Jones*: Peak= Mon-Sun HE 0700 – 2200; Off-peak Hours= Mon-Sun HE 2300 – 0600. (HE = Hour Ending)

13 See the Appendix to this briefing paper for tabular versions of the data presented graphically above.

3.1 California pricing hubs

Figure 1. NP15 wholesale electricity prices on July 18, 2005 ($/MWh)

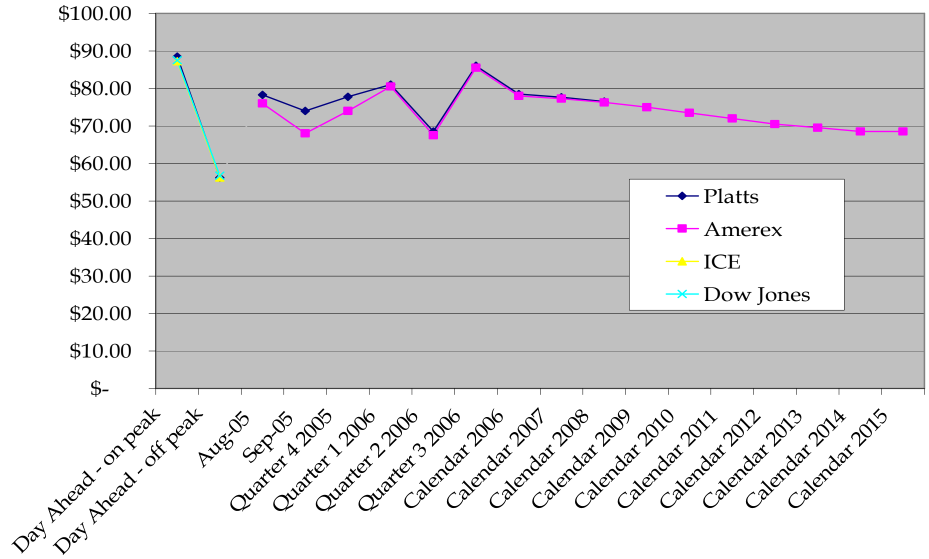


Figure 2. SP15 wholesale electricity prices on July 18, 2005 ($/MWh)

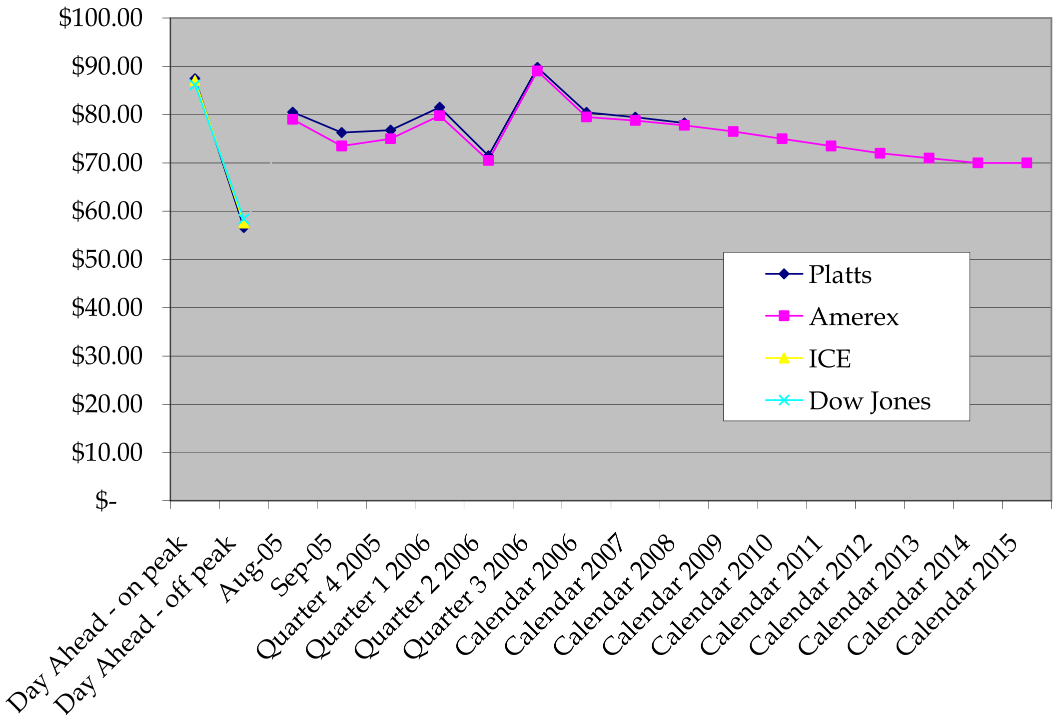
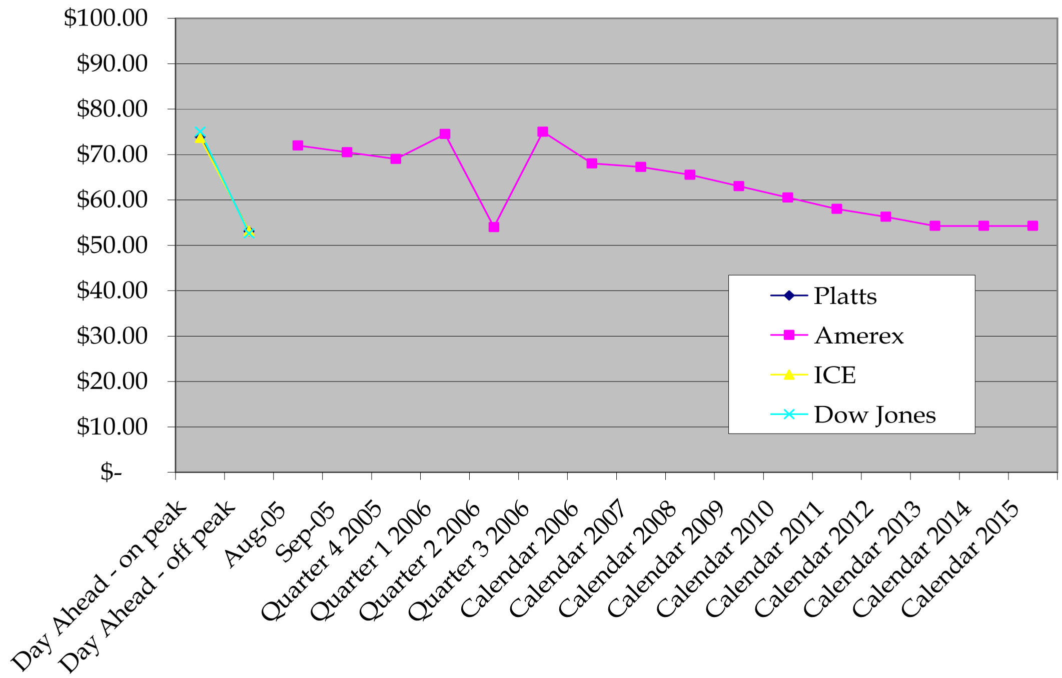


Figure 3. COB wholesale electricity prices on July 18, 2005 ($/MWh)



3.2 Other WECC pricing hubs

Figure 4. Mid-C wholesale electricity prices on July 18, 2005 ($/MWh)

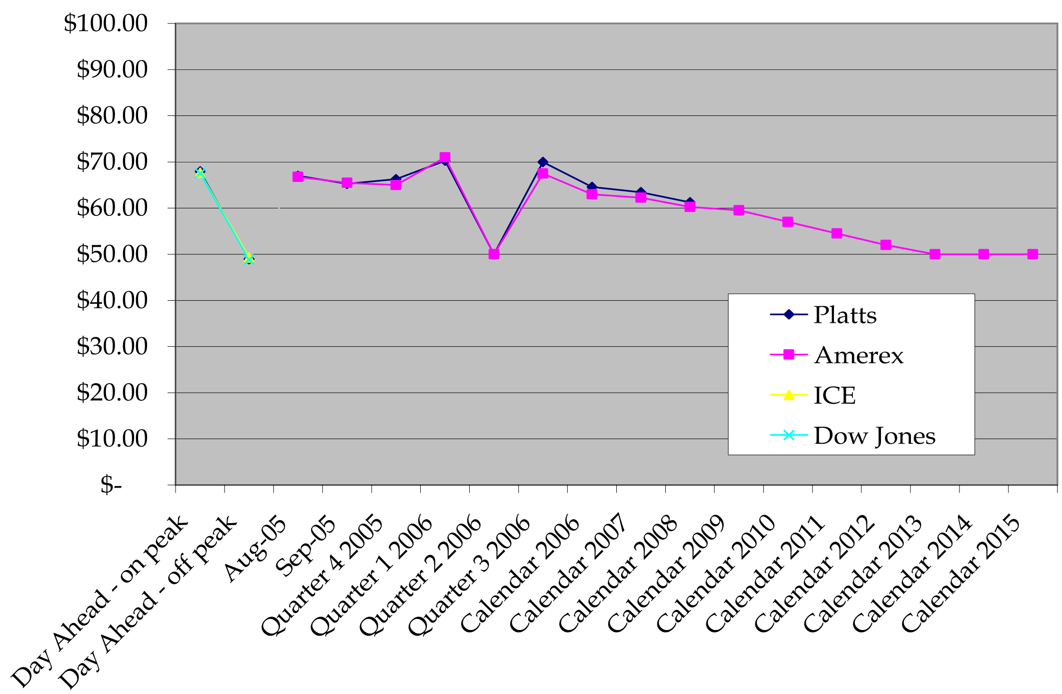


Figure 5. Palo Verde wholesale electricity prices on July 18, 2005 ($/MWh)

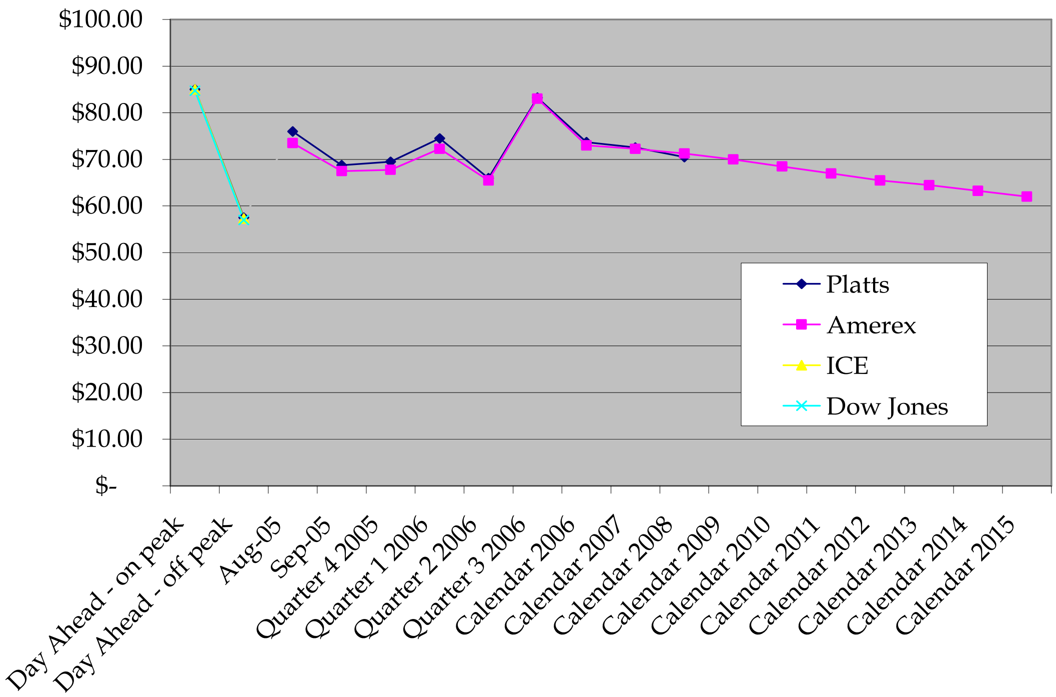
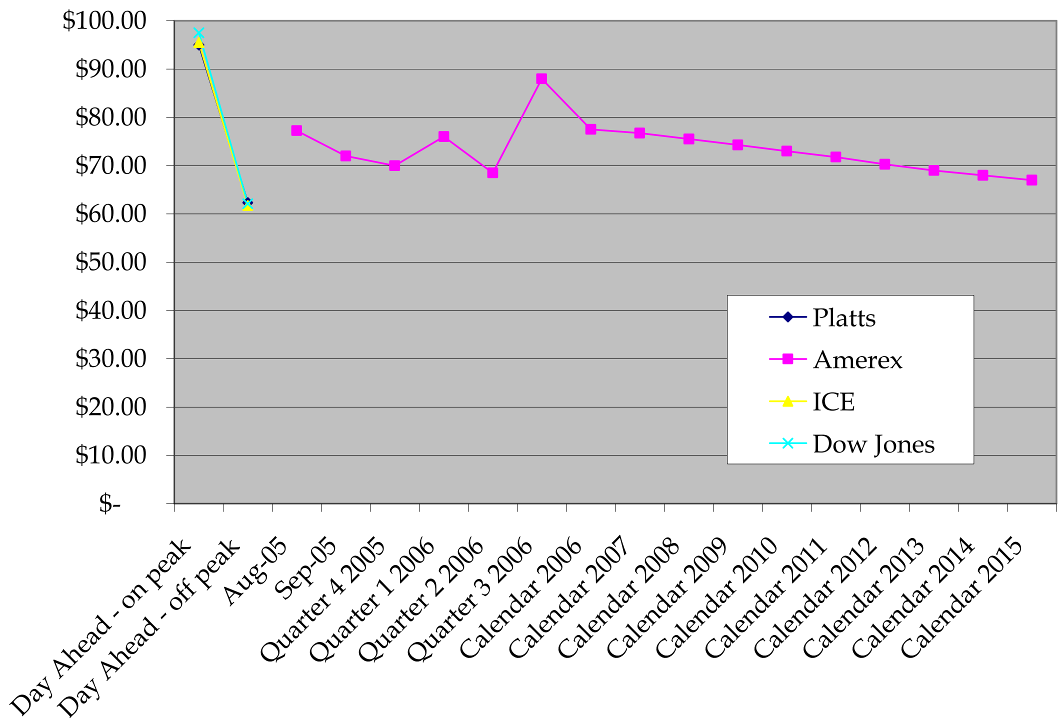


Figure 6. Mead wholesale electricity prices on July 18, 2005 ($/MWh)



4 Appendix

4.1 NP15 wholesale electricity prices on July 18, 2005 ($/MWh)

	Platts	Amerex	ICE	Dow Jones
Day Ahead - on peak	$ 88.48	n/a	$ 87.24	$ 87.52
Day Ahead - off peak	$ 56.17	n/a	$ 56.25	$ 56.70
Aug-05	$ 78.25	$ 76.00	n/a	n/a
Sep-05	$ 74.00	$ 68.00	n/a	n/a
Quarter 4 2005	$ 77.75	$ 74.00	n/a	n/a
Quarter 1 2006	$ 81.00	$ 80.50	n/a	n/a
Quarter 2 2006	$ 68.50	$ 67.50	n/a	n/a
Quarter 3 2006	$ 86.00	$ 85.50	n/a	n/a
Calendar 2006	$ 78.50	$ 78.00	n/a	n/a
Calendar 2007	$ 77.65	$ 77.25	n/a	n/a
Calendar 2008	$ 76.50	$ 76.25	n/a	n/a
Calendar 2009	n/a	$ 75.00	n/a	n/a
Calendar 2010	n/a	$ 73.50	n/a	n/a
Calendar 2011	n/a	$ 72.00	n/a	n/a
Calendar 2012	n/a	$ 70.50	n/a	n/a
Calendar 2013	n/a	$ 69.50	n/a	n/a
Calendar 2014	n/a	$ 68.50	n/a	n/a
Calendar 2015	n/a	$ 68.50	n/a	n/a

4.2 SP15 wholesale electricity prices on July 18, 2005 ($/MWh)

	Platts	Amerex	ICE	Dow Jones
Day Ahead - on peak	$ 87.43	n/a	$ 87.05	$ 86.13
Day Ahead - off peak	$ 56.61	n/a	$ 57.54	$ 58.36
Aug-05	$ 80.50	$ 79.00	n/a	n/a
Sep-05	$ 76.25	$ 73.50	n/a	n/a
Quarter 4 2005	$ 76.75	$ 75.00	n/a	n/a
Quarter 1 2006	$ 81.50	$ 79.75	n/a	n/a
Quarter 2 2006	$ 71.50	$ 70.50	n/a	n/a
Quarter 3 2006	$ 89.75	$ 89.00	n/a	n/a
Calendar 2006	$ 80.45	$ 79.50	n/a	n/a
Calendar 2007	$ 79.45	$ 78.75	n/a	n/a
Calendar 2008	$ 78.25	$ 77.75	n/a	n/a
Calendar 2009	n/a	$ 76.50	n/a	n/a
Calendar 2010	n/a	$ 75.00	n/a	n/a
Calendar 2011	n/a	$ 73.50	n/a	n/a
Calendar 2012	n/a	$ 72.00	n/a	n/a
Calendar 2013	n/a	$ 71.00	n/a	n/a
Calendar 2014	n/a	$ 70.00	n/a	n/a
Calendar 2015	n/a	$ 70.00	n/a	n/a

4.3 COB wholesale electricity prices on July 18, 2005 ($/MWh)

	Platts	Amerex	ICE	Dow Jones
Day Ahead - on peak	$ 73.88	n/a	$ 73.66	$ 75.05
Day Ahead - off peak	$ 53.08	n/a	$ 53.15	$ 52.63
Aug-05	n/a	$ 72.00	n/a	n/a
Sep-05	n/a	$ 70.50	n/a	n/a
Quarter 4 2005	n/a	$ 69.00	n/a	n/a
Quarter 1 2006	n/a	$ 74.50	n/a	n/a
Quarter 2 2006	n/a	$ 54.00	n/a	n/a
Quarter 3 2006	n/a	$ 75.00	n/a	n/a
Calendar 2006	n/a	$ 68.00	n/a	n/a
Calendar 2007	n/a	$ 67.25	n/a	n/a
Calendar 2008	n/a	$ 65.50	n/a	n/a
Calendar 2009	n/a	$ 63.00	n/a	n/a
Calendar 2010	n/a	$ 60.50	n/a	n/a
Calendar 2011	n/a	$ 58.00	n/a	n/a
Calendar 2012	n/a	$ 56.25	n/a	n/a
Calendar 2013	n/a	$ 54.25	n/a	n/a
Calendar 2014	n/a	$ 54.25	n/a	n/a
Calendar 2015	n/a	$ 54.25	n/a	n/a

4.4 Mid-C wholesale electricity prices on July 18, 2005 ($/MWh)

	Platts	Amerex	ICE	Dow Jones
Day Ahead - on peak	$ 67.92	n/a	$ 67.65	$ 67.53
Day Ahead - off peak	$ 48.95	n/a	$ 49.26	$ 48.88
Aug-05	$ 67.00	$ 66.75	n/a	n/a
Sep-05	$ 65.25	$ 65.50	n/a	n/a
Quarter 4 2005	$ 66.25	$ 65.00	n/a	n/a
Quarter 1 2006	$ 70.25	$ 71.00	n/a	n/a
Quarter 2 2006	$ 50.00	$ 50.00	n/a	n/a
Quarter 3 2006	$ 70.00	$ 67.50	n/a	n/a
Calendar 2006	$ 64.55	$ 63.00	n/a	n/a
Calendar 2007	$ 63.45	$ 62.25	n/a	n/a
Calendar 2008	$ 61.25	$ 60.25	n/a	n/a
Calendar 2009	n/a	$ 59.50	n/a	n/a
Calendar 2010	n/a	$ 57.00	n/a	n/a
Calendar 2011	n/a	$ 54.50	n/a	n/a
Calendar 2012	n/a	$ 52.00	n/a	n/a
Calendar 2013	n/a	$ 50.00	n/a	n/a
Calendar 2014	n/a	$ 50.00	n/a	n/a
Calendar 2015	n/a	$ 50.00	n/a	n/a

4.5 Palo Verde wholesale electricity prices on July 18, 2005 ($/MWh)

	Platts	Amerex	ICE	Dow Jones
Day Ahead - on peak	$ 85.00	n/a	$ 85.04	$ 84.73
Day Ahead - off peak	$ 57.53	n/a	$ 57.32	$ 57.00
Aug-05	$ 76.00	$ 73.50	n/a	n/a
Sep-05	$ 68.75	$ 67.50	n/a	n/a
Quarter 4 2005	$ 69.50	$ 67.75	n/a	n/a
Quarter 1 2006	$ 74.50	$ 72.25	n/a	n/a
Quarter 2 2006	$ 66.00	$ 65.50	n/a	n/a
Quarter 3 2006	$ 83.25	$ 83.00	n/a	n/a
Calendar 2006	$ 73.70	$ 73.00	n/a	n/a
Calendar 2007	$ 72.55	$ 72.25	n/a	n/a
Calendar 2008	$ 70.50	$ 71.25	n/a	n/a
Calendar 2009	n/a	$ 70.00	n/a	n/a
Calendar 2010	n/a	$ 68.50	n/a	n/a
Calendar 2011	n/a	$ 67.00	n/a	n/a
Calendar 2012	n/a	$ 65.50	n/a	n/a
Calendar 2013	n/a	$ 64.50	n/a	n/a
Calendar 2014	n/a	$ 63.25	n/a	n/a
Calendar 2015	n/a	$ 62.00	n/a	n/a

4.6 Mead wholesale electricity prices on July 18, 2005 ($/MWh)

	Platts	Amerex	ICE	Dow Jones
Day Ahead - on peak	$ 95.01	n/a	$ 95.47	$ 97.51
Day Ahead - off peak	$ 62.33	n/a	$ 61.75	$ 62.13
Aug-05	n/a	$ 77.25	n/a	n/a
Sep-05	n/a	$ 72.00	n/a	n/a
Quarter 4 2005	n/a	$ 70.00	n/a	n/a
Quarter 1 2006	n/a	$ 76.00	n/a	n/a
Quarter 2 2006	n/a	$ 68.50	n/a	n/a
Quarter 3 2006	n/a	$ 88.00	n/a	n/a
Calendar 2006	n/a	$ 77.50	n/a	n/a
Calendar 2007	n/a	$ 76.75	n/a	n/a
Calendar 2008	n/a	$ 75.50	n/a	n/a
Calendar 2009	n/a	$ 74.25	n/a	n/a
Calendar 2010	n/a	$ 73.00	n/a	n/a
Calendar 2011	n/a	$ 71.75	n/a	n/a
Calendar 2012	n/a	$ 70.25	n/a	n/a
Calendar 2013	n/a	$ 69.00	n/a	n/a
Calendar 2014	n/a	$ 68.00	n/a	n/a
Calendar 2015	n/a	$ 67.00	n/a	n/a

Attachment G

Overview Of The Availability Of Detailed
Monthly Production Data From Hydroelectric Facilities
Prepared By Julia Frayer, London Economics.

Overview of the availability of detailed monthly production data from hydroelectric facilities

prepared by London Economics International LLC for the California Energy Commission

August 12, 2005

1 Introduction

Pacific Gas & Electric Company ("PG&E") has claimed in testimony supporting its appeal of the Executive Director's June 3, 2005 Notice of Intent ("NOI") that aggregated long-term planning data on consumption and production of electricity at a quarterly level would provide proprietary information to market participants on the IOUs' seasonal procurement needs and is thus damaging to ratepayers.[1] After acknowledging that the seasonality of its position is primarily hydro-based, PG&E further states in its testimony that the "seasonal magnitude" of "Northern California's generation and supply requirements" is "not publicly known."[2] PG&E's witness, Roy Kuga, implies that no similar information on the seasonal requirements of the IOUs is available. Witness Kuga also claims that "the release of the quarterly capacity data… would allow market participants to understand not only PG&E's peak requirements, but also allow market participants to ascertain PG&E's market strategy… [with respect to] the seasonal requirement."[3]

These claims ignore the availability of substantial amounts of historical hourly and monthly data on both demand and supply, which market participants already use to develop an understanding of the seasonal load profile for the California Investor Owned Utilities ("IOUs"). For example, hourly demand data is available at the control area and planning area levels from filings made to the Federal Energy Regulatory Commission ("FERC").[4] Hourly production data from most larger utility generation plants (greater than 73 MW) and industrial steam plants greater than 2.9 MW is available from the U.S. Environmental Protection Agency's ("EPA")

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1 *See* PG&E's appeal at 3: "The release of the quarterly data would… publicize the magnitude of PG&E's seasonal energy and capacity positions… Unlike SDG&E and SCE, PG&E generates, procures and utilizes significant quantities of seasonal energy and capacity on its system, given its large hydroelectric resources and proximity to similar resources in the Northwest." Furthermore, PG&E's witness Roy Kuga notes in his testimony that "its no secret that PG&E has a lot of hydro and wind generation" (*see* Kuga at 3-4).

2 *See* PG&E's appeal at 3.

3 *See* Kuga at 3.

4 "Part III of FERC Form 714 is to be completed by each electric utility or group of electric utilities which constitute a planning area and has an annual peak demand that is greater than 200 MW". *Source:* http://www.ferc.gov/docs-filing/eforms/form-714/overview.asp.

Continuous Emission Monitoring System ("CEMS"),[5] and monthly production and fuel consumption data on a plant or unit level is available through mandatory filings made by power plant operators to the EIA on Form 906.[6] In addition, detailed information about the seasonal buying and selling strategies of PG&E can be discerned from the transactions data filed publicly with FERC's Electronic Quarterly Reporting ("EQR") system.[7]

PG&E raises the issue because of the highly seasonal production nature of its hydro fleet. Yet, the monthly production of the fleet on a unit by unit basis is filed for public review with the EIA, with only a 45 day delay for monthly "flash estimates" of filed monthly data and release of the entire information set within approximately 75 days. Because of its frequency and unit-level specification, this monthly data from the EIA is a source of much more detailed information on PG&E's needs than the aggregated summary tables proposed by the NOI. Moreover, because of the "actual" nature of this monthly data versus the "estimated" character of the planning information in the aggregated summary tables, this monthly data provides a much more accurate representation of seasonal net short and net long positions of the IOUs under different hydrological conditions, especially over the short term. Given the public availability of actual historical monthly data, the release of aggregated summary tables showing quarterly estimates for the years 2009 – 2016 cannot be said to provide information about seasonality that is not generally known. Indeed, one could credibly argue that the historical data, such as historical production data, is potentially more sensitive than the annual and quarterly aggregated summary tables because the historical data is disaggregated at the plant or unit level and is available on a much more frequent basis (monthly or even hourly, for some thermal plants).

Moreover, since the historical data is available almost in real time, it is likely to more accurately represent the IOUs' real-time needs, which are relatively inelastic. In contrast, the aggregated summary tables will not disclose the supply-demand projections over the next three years. The objective of the aggregated summary tables is to describe the long-term needs of the IOUs. If one takes into account all of the alternatives for energy procurement available to the IOUs, their long-term needs can be characterized in the aggregate as fairly elastic. This, in turn, would make monopolization impossible, as I discuss in a separate paper entitled "Analyzing the potential for the exercise of market power in the long term procurement of energy in California."

In contrast to the rebuttal testimony prepared by the IOUs, conventional wisdom coupled with well-accepted economic theory suggests that the release of the quarterly aggregated summary

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5 *See* http://www.epa.gov/ttn/emc/cem.html

6 In fact, historical monthly data on production by fuel type, consumption, production costs, and inter-utility transactions is also available for the IOUs through the Utility Monthly Fuel and Operations Report ("UMFOR"). Recent re-affirmation of the public nature of such data has come in a recent (May 9, 2005) ALJ Ruling in the CPUC Proceeding R. 04-04-025, which is described in Attachment H, Demand forecast and resource plan data: disclosure mandates of the CPUC in R.04-04-025, prepared by Dr. Michael Jaske, Energy Commission staff.

7 I discuss the wealth of data available through the FERC EQRs in Attachment E entitled, *Guide to FERC Electric Quarterly Reports.*

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tables with estimated information on supply and demand from 2009 through 2016 *does* provide vital signals for new investment and thus would benefit the IOUs' ratepayers in the long run. Indeed, Witness Kuga concedes that the aggregated summary tables would "indicate to the market what type of resources are likely to be sought."[8] The quarterly aggregated summary tables, in complement to the annual aggregated summary tables, will provide valuable information on the long-term seasonal needs of the IOUs and thus enable an appropriate investment response. For example, if energy production from existing resources is expected to be sufficiently distinct between seasons in the longer term, the quarterly aggregate summary tables would signal the need for flexible, cost-effective generation that could be energized only in those seasons when hydrological production is scarce – in other words, peaking or intermediate generation rather than baseload generation. Alternatively, such a seasonal profile may motivate a large industrial customer to re-schedule its industrial process and seasonal electricity demand in order to provide demand-side management ("DSM"). Indeed, there are no substitutes for the signaling benefits achieved through the release of the quarterly aggregated summary tables. Though future Request for Offers ("RFOs") may specifically solicit seasonal generation or DSM, the RFOs will typically not provide appropriate lead time for new developers to credibly submit an offer or for industrial customers to re-arrange commercial activities to realize DSM initiatives.[9] Thus, the aggregated summary tables will provide important estimate of need which prospective generation developers and potential DSM sponsors can then use to prepare for future RFO opportunities.

8 *See* Kuga at 3.

9 I discuss the issue of lead time for new developers and RFO timing requirements further in another briefing paper that focuses specifically on the IOUs' long term procurement processes. Please refer to Attachment B, entitled *IOU long term procurement, RFOs, auction theory and information release policy*.

2 Overview of EIA Form 906 – Power Plant Report

The EIA (Energy Information Administration of the U.S. Department of Energy) collects the following information from all utility and non-utility electric generating plants[10] in the U.S. on a monthly and annual basis in Form 906:

- plant name and location;
- prime mover type;
- electric power generation;
- fuel consumption;
- fuel heat content; and
- fossil fuel stock.

EIA-906 is a mandatory filing on an annual basis for power plants which have a nameplate capacity of 1 MW or above and are connected to the electric grid. Monthly filings are required of plants with capacity greater than fuel-specific threshold levels: currently, this level is 80 MW for hydroelectric plants and 200 MW for most thermal power plants.

The EIA-906 is filed by all electric power plants except for Combined Heat and Power Plant ("CHP"), which supply similar information through EIA-920. The data collected through EIA-906 is used to monitor the current status and future trends of the electric power industry. The EIA uses this data to prepare reports, such as the *Electricity Power Monthly.*

As of January 2001, EIA-906 form superseded EIA-759 and EIA-900 forms[11]. A sample group of plants (above a particular threshold nameplate capacity) are required to report on a monthly basis, in order to reduce the reporting burden for all generators. Those plants not chosen to respond monthly must report annually. The method of data collection was changed from the entire universe of plants to this "sample" method in 1998, primarily in response to divestment of power plants by regulated utilities and was geared towards reducing costs of compliance.[12]

Currently, the survey collects monthly data from 1,418 plants and annual data from 2,973 plants. The type of data provided in the monthly and annual collections is described in the next sub-sections, while Section 1 contains actual excerpts of hydro-electric monthly production data for the California IOUs.

2.1 EIA-906- Monthly Submission

Electric generating plants selected to respond on a monthly basis must submit the form reproduced in Figure 1 below electronically within 10 days of the end of the reporting month. The EIA then publishes a "flash estimate" of monthly production within 45 days, followed by

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10 EIA-906, Power Plant Report, *Form and Instructions.*

11 EIA-759 was used to collect electric power industry information from 1982 until it was superseded by EIA-906. EIA-906 was introduced in 1996 to collect sales information on unregulated utilities. It was later modified to collect net generation, consumption and fuel stock. Source: *Electric Power Monthly*, Technical Notes, June 2005.

12 Source: telephone conversation with EIA staff, Channele Wirman, July 20, 2005.

the entire database of information within two to three months. The reporting requirements for each field are detailed in Figure 2.

Figure 1. EIA-906 Monthly Submission Form[13]

U.S. Department of Energy Energy Information Administration Form EIA-906 (2004)	*POWER PLANT REPORT*	Form Approved OMB No. 1905-0129 Approval Expires 11/30/07
RESPONDENT NAME:	RESPONDENT ID:	REPORTING PERIOD:
TYPE OF RESPONDENT: REGULATED GENERATOR ( ) UNREGULATED GENERATOR ( )		MONTHLY SUBMISSION

PLANT NAME (a)	PLANT ID (b)	STATE (c)	PRIME MOVER TYPE (d)	ENERGY SOURCE (e)	GENERATOR NAMEPLATE CAPACITY (f)	GENERATION (g)	ENERGY SOURCE: CONSUMED DURING REPORTING MONTH (h)	ENERGY SOURCE: STOCKS AT END OF REPORTING MONTH (i)	HEAT CONTENT PER UNIT OF FUEL (j)	
				If you used a fuel that is not pre-printed, report it in the blank row associated with each prime mover.	Report in Megawatts. Report one (1) value for each prime mover.	Report net generation in Megawatthours; one (1) value for each prime mover	If a pre-printed fuel was not used, enter a zero (0). Reporting units: Solids = Tons Liquids = Barrels Gases = Thousands of cubic feet	Report stocks at the plant level, not at the prime mover level.	Reporting units: Solids: Million Btu per ton Liquids: Million Btu per barrel Gases: Million Btu per thousand cubic feet	

Figure 2. Guide to Data Fields in the monthly collection of EIA-906 form[14]

EIA-906 Filing Field	Data Requirement
type_of_respondent	*Possible responses include: regulated generator, unregulated generator.*
plant_name	*The common name by which the plant is known. Change in plant name should be reported to EIA.*
plant_id	*Unique ID assigned to the plant by EIA. This cannot be changed.*
State	*U.S postal abbreviation to show the state in which the plant is physically located.*
prime_mover_type	*The plant's prime mover code from the following list: steam turbine, combustion turbine, internal combustion engine, combined cycle combustion (separately for turbine part and steam part), combined cycle single shaft, hydraulic turbine, hydraulic turbine (reversible – pumped storage), photovoltaic, wind turbine, compressed air energy storage, fuel cell and other.*

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13 EIA-906, Power Plant Report, *Form and Instructions.*

14 EIA-906, Power Plant Report, *Form and Instructions* with standard industry definitions from *Energy Velocity.*

EIA-906 Filing Field	Data Requirement
generator_nameplate_capacity	*Maximum Generator Nameplate Capacity: the highest value nameplate associated with the plant, reported in megawatts rounded to the nearest tenth.*
generation	*Total monthly net generation, reported in megawatthours ("MWh"). Net generation is defined as gross energy output minus electrical energy utilization. An explanation is required for negative net generation (i.e., for pumped storage plants that report gross generation less pumping energy). Combined cycle units should report combustion turbine and steam turbine separately.*
energy_source (consumed_during_reported_month)	*This field indicates the total quantity of fuel consumed, based on one of the 34 energy source codes including coal types, organic wastes, oil and its derivatives, natural gas and other gas variants, steam, pumped storage, nuclear, geothermal, solar, conventional hydroelectric turbine, and wind. The units for solid fuels is tons, liquid fuels are reported in barrels and gaseous fuels in thousands of cubic feet. For pumped storage plants, this field will report pumping energy in MWh. This field should be populated with actual values (though estimated values can be used, if necessary). The total units of fuel consumption must include start-up and flame stabilization fuels.*
energy_source (stock_at_the_end_of_reporting_month)	*This field reports the stock of fuel that the plant has in storage for coal, distillate and residual fuel oils and petroleum coke at the end of the month*
heat_content_per_unit_of_fuel	*This filed identifies the average heat content of the fuel burned over the reporting month, using gross or higher heating value per unit of fuel consumed. If fuel heat content cannot be reported "as burned", data may be obtained from the fuel supplier on an "as received" basis.*

2.2 EIA-906 – Annual Submission

The annual submission form is very similar to the monthly submission, as highlighted in Figure 3 below. Both the annual and monthly forms have the same fields, except that the data for generation (g) field and energy consumed (h) field has to be reported for the entire calendar year. In addition, the stock of fossil fuel needs to be reported as of the end of the year. There is an additional filing field which is only applicable for cogenerators: they are required to report useful thermal output for processes other than power generation in million Btu.

Figure 3. EIA-906 - Annual Submission Form[15]

U.S. Department of Energy Energy Information Administration Form EIA-906 (2003)	*POWER PLANT REPORT*	Form Approved OMB No. 1905-0129 Approval Expires 11/30/07
RESPONDENT NAME:	RESPONDENT ID:	REPORTING PERIOD:
TYPE OF RESPONDENT: REGULATED GENERATOR ( ) UNREGULATED GENERATOR ( )		ANNUAL SUBMISSION

PLANT NAME (a)	PLANT ID (b)	STATE (c)	PRIME MOVER TYPE (d)	ENERGY SOURCE (e)	GENERATOR NAMEPLATE CAPACITY (f)	GENERATION (g)	ENERGY SOURCE: CONSUMED DURING REPORTING YEAR (h)	ENERGY SOURCE: STOCKS AT END OF REPORTING YEAR (i)	HEAT CONTENT PER UNIT OF FUEL (j)	COGENERATORS ONLY: USEFUL THERMAL OUTPUT FOR PROCESSES OTHER THAN POWER GENERATION (k)
				If you used a fuel that is not pre-printed, report it in the blank row associated with each prime mover.	Report in Megawatts. Report one (1) value for each prime mover.	Cogenerators: Report gross generation. All Others: Report net generation. Report in Megawatthours; one (1) value for each prime mover	If a pre-printed fuel was not used, enter a zero (0). Reporting units: Solids = Tons Liquids = Barrels Gases = Thousands of cubic feet	Report stocks at the plant level, not at the prime mover level.	Reporting units: Solids: Million Btu per ton Liquids: Million Btu per barrel Gases: Million Btu per thousand cubic feet	Report in million Btu. Report only one (1) value per plant. **Not sure what to report?** Contact: Channele Carner 202-287-1928 channele.carner@eia.doe.gov

The data in column (i) referring to stock at the end of the reporting period is kept ***confidential*** and not reported to the public. All other information contained the form, as well as in the monthly form, is available to the public.

2.3 Sampling Process

As indicated earlier, plants above a particular threshold are required to report their data on a monthly submission. Currently, the threshold for mandatory reporting is 80 MW for all hydroelectric plants nationwide and 200 MW for most thermal power plants. Some of the companies which have plants above the threshold also voluntarily choose to report monthly production for plants that are below the threshold. As an example, PG&E has continued to reported monthly production for its smaller hydroelectric facilities on a voluntary basis through 2004. In addition, beginning in 2003, plants under 1 MW of installed nameplate capacity are no longer required to report on the Form EIA-906.

The threshold level for mandatory monthly reporting varies by fuel type and by state and/or region to ensure that the estimates from the monthly data are statistically significant. The sample of plants reporting monthly was reevaluated in 2004 to ensure continued statistical

15 EIA-906, Power Plant Report, *Form and Instructions*

significance.[16] For example, in 2004 the sample was revised and reduced in size: currently, 1,418 plants are required to provide monthly data, while 2,973 plants file annually. The sample may be reevaluated every three years as part of the EIA budgeting process, however, such reevaluation is not mandatory. Budgetary approval is necessary to add new plants to the sample. Therefore, no new plants are likely to be added to the sample within the next three years. This suggests that the EIA is confident that that the plants currently required to file monthly already provide a representative snapshot of monthly energy production by fuel type for the state and region.

EIA-906 data is finalized once data has also been collected from annual respondents. This data is put through edit checks. Data from consistent responses is apportioned to the months (by state, fuel and sector) using the ratio of monthly data collected to the sum of that monthly data,[17] which presumes that the distribution of monthly generation for plants submitting annual data is similar to the distribution of monthly generation of plants submitting monthly data.

Annual submissions from previous years are used to estimate a regression model for estimating generation by fuel type and by sector at the state level. This model's Relative Standard Error ("RSE") is then evaluated.

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16 Source: telephone conversation with EIA staff, Channele Wirman, July 20, 2005.

17 Edit checks include range checks, comparisons with historical data and consistency checks (between fuel consumption and generation numbers). Source: *Electric Power Monthly*, Technical Notes, June 2005

3 Monthly data available on hydroelectric generation in California

The EIA-906 collects generation data for all fuel types including pumped storage and conventional hydro. Given that hydroelectric generation is most prone to seasonal trends and in order to provide a sample of the breadth of data available publicly on seasonal production trends, we have extracted data for conventional hydro production for all reporting parties in California. For illustrative purposes, we have not included pumped storage plants, as their net production figures are skewed by pumping energy and their operating decision is more a function of arbitrage between peak versus off-peak rather than hydrological conditions. Since 1998, EIA has not collected monthly data for from the entire universe of U.S. power plants, but only from those power plants above the capacity-denominated threshold, as discussed above. In 2004, 42 hydroelectric plants in California with nameplate capacity of 80 MW or higher reported monthly data. These plants represent 69% of the total hydroelectric generation capacity in the state based on a comparison of reported data on EIA Form 906 and EIA Form 860 (which tracks nameplate capacity and other information from all existing and proposed U.S. power plants greater than 1 MW[18]).

Furthermore, it is important to note that some plants that are below the threshold voluntarily report the monthly production information. For example, in 2004, 68 plants with capacity of less than 80 MW reported monthly. If we add these to the greater than 80 MW capacity ones, plants representing 83% of the total hydroelectric generation capacity report their generation figures on a monthly basis in California. These additional voluntary monthly filings were made by companies that have other plants that are required to be report monthly; the reporting companies have thus chosen for convenience to include all their plants each month, although they are not required to do so.[19] Nationally, 329 hydroelectric plants reported monthly data, out of which over 184 had nameplate capacity of 80 MW or higher.

As an indication of the "sampling" method's aggregate accuracy, EIA's reported RSE for net generation for electric utilities in California for September 2004 was 1% and for April 2005 was 2%.[20] The fact that the RSE is so small signifies that total generation by fuel type, by state, and by sector can be estimated with a fair degree of certainty (at least for hydroelectric plants in California). If a utility has been submitting data for a number of years, then there should be enough data points to estimate a robust regression model to forecast future generation. Any new information release would help improve the reliability of the estimate and reduce its standard error.

The form only requires the name of the operator, and not the owner or holding company; thus, some additional information on ownership is necessary for assigning generation to various parties. For example, San Diego Gas and Electric ("SDG&E") owns the San Onofre Nuclear Power Plant with a nameplate capacity of 542 MW, which is operated by Southern California

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18 *See* http://www.eia.doe.gov/cneaf/electricity/forms/help/eia860help.html

19 Source: email from Channele Wirman, EIA July 19, 2005

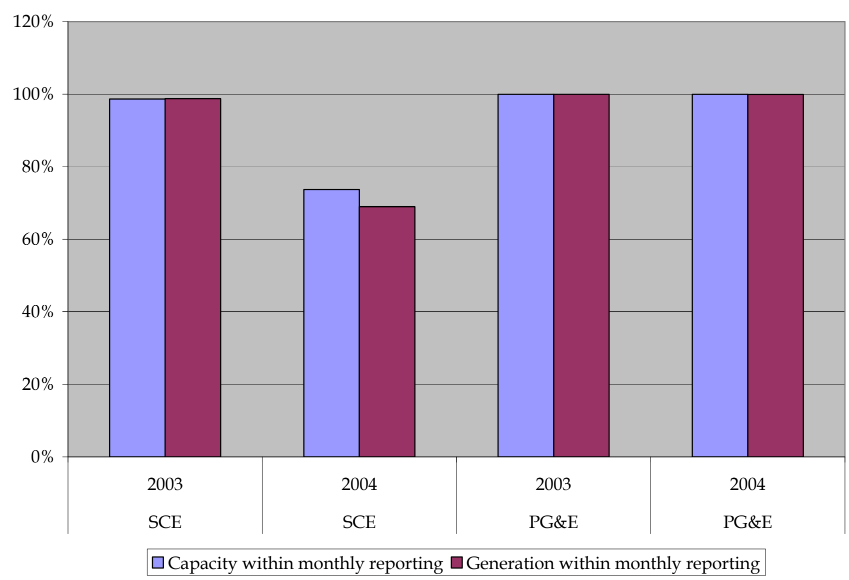
20 Source: *Electric Power Monthly*, EIA

Edison ("SCE"). The monthly production for this plant is reported by SCE. For sake of illustration, I discuss below the historical seasonality of hydroelectric production for the two IOUs that operate hydroelectric plants in the state. SDG&E (Sempra Energy is the holding company) does not operate or own any hydro power plants in California, nor to my knowledge directly owns any plants. Thus, I have presented below the available data for PG&E and SCE. Similar information is readily available for all other hydro operators in the state. Indeed, the monthly hydro production data for all utilities in California is currently available from 1970 through April 2005 (as of July 20th 2005).

Before I discuss the observable trends in the data for SCE and PG&E, it is useful to understand the breadth of the historical data from the EIA 906. Until 2004, SCE and PG&E submitted monthly submissions covering almost all of each of their entire hydroelectric portfolios. PG&E continues to report monthly production for plants accounting for almost 100% of its capacity and generation. In 2004, SCE reported monthly production for plants with nameplate capacity of 80 MW or above, accounting for slightly less than 70% of its conventional hydroelectric generation on an annual basis. Figure 4 shows a comparison of the percentage of capacity versus percentage of generation that is captured in the monthly submissions on an annual basis. The UMFOR filings made by the IOUs under a recent ALJ ruling, however, provide us with a total hydroelectric production figure for 2004. Through a comparison of the UMFOR data and the information filed with the EIA Form 906 on both conventional and pumped storage hydro, the EIA mandatory filing requirement for plants greater than 80 MW has required SCE to report approximately 67% to 78% of its monthly hydroelectric generation last year, while PG&E reported effectively all of its monthly hydroelectric generation last year.

Moreover, given availability of pre-2004 data, and the RSE and survey approach taken by the EIA, it is fairly straightforward for a market participant to extrapolate and estimate plant-level production figures for the smaller plants.

Figure 4. Coverage of monthly submission for SCE and PG&E on an annual basis



Figures 5 and 6 highlight the plant-level monthly generation for all conventional[21] hydroelectric plants operated by SCE in CA for 2003 and 2004 respectively. Figures 7 and 8 highlight similar information for PG&E.

[21] Excludes pumped storage pumping load and production data.

Figure 5. Plant-level conventional hydroelectric monthly generation for SCE , 2003

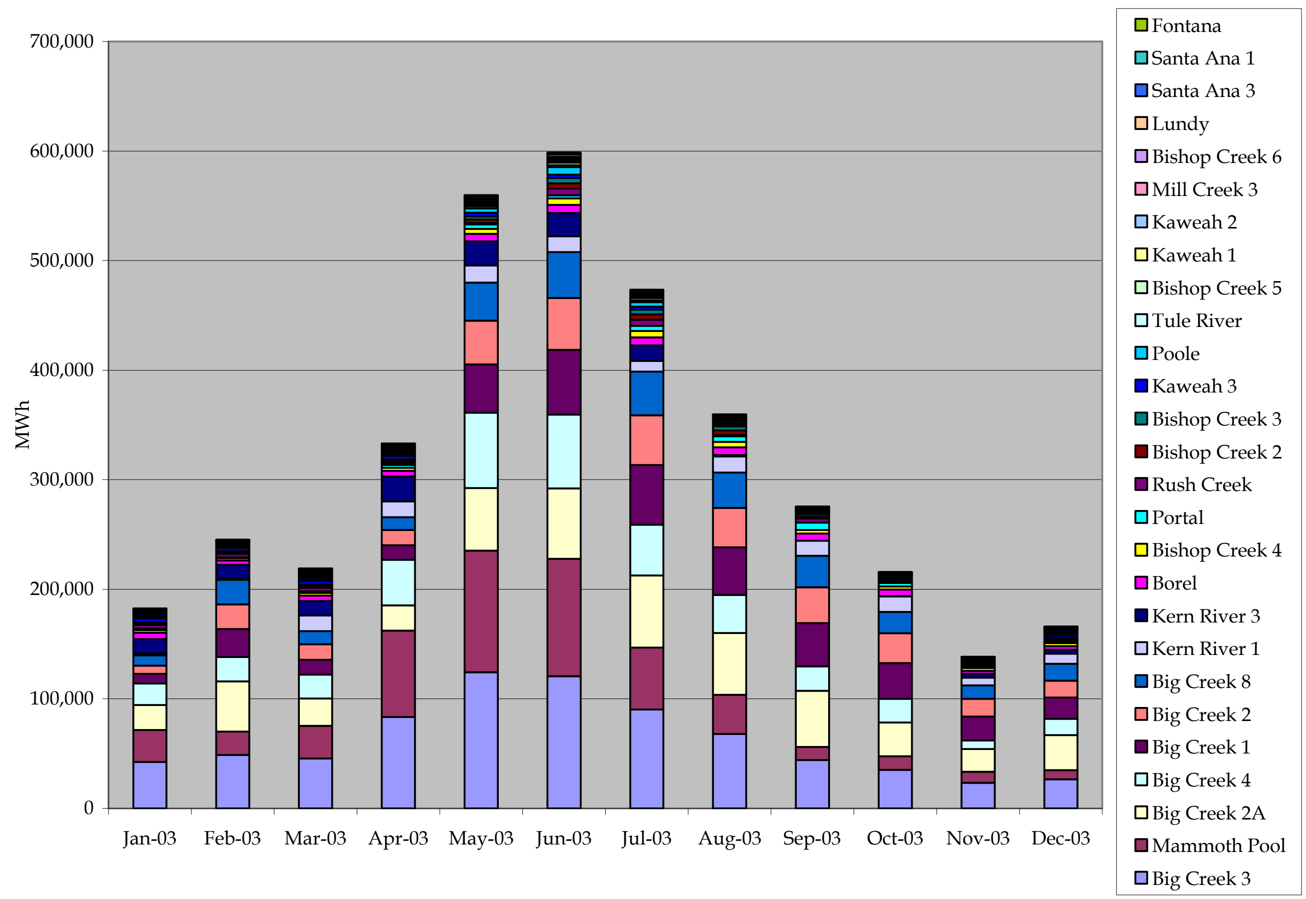


Figure 6 Plant-level conventional hydroelectric monthly generation for SCE , 2004

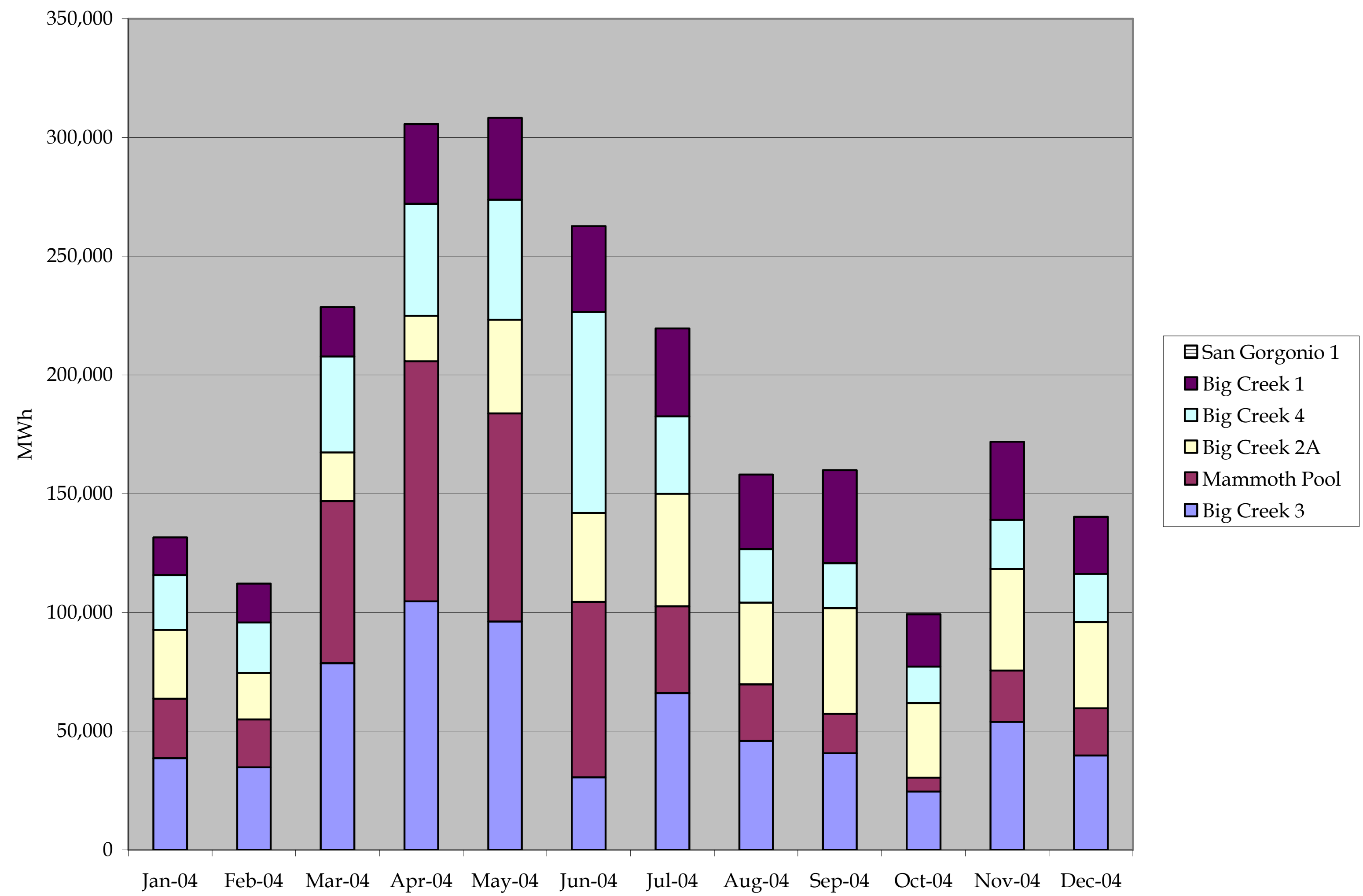


Figure 7. Plant-level conventional hydroelectric monthly generation for PG&E , 2003

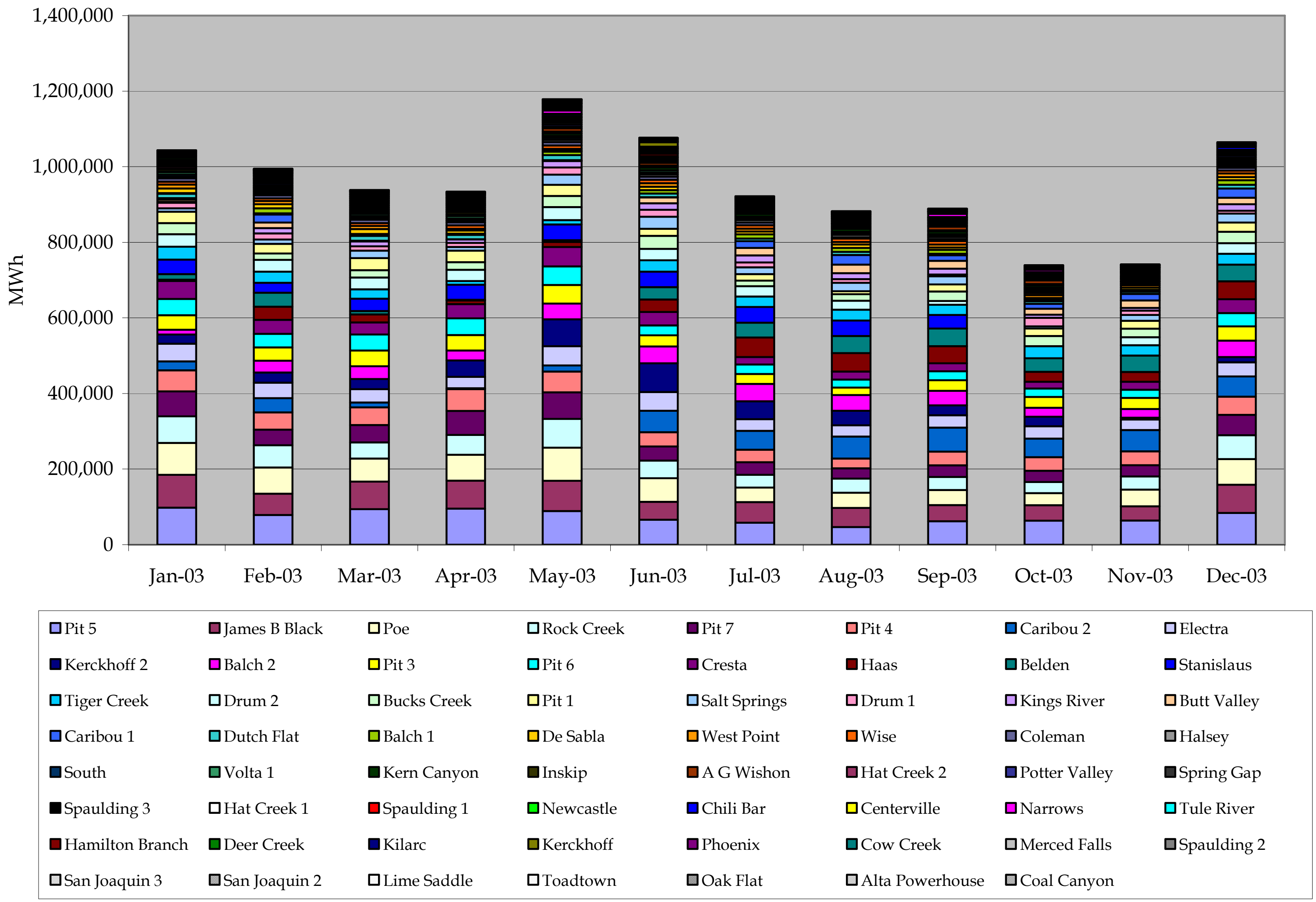


Figure 8. Plant-level conventional hydroelectric monthly generation for PG&E , 2004

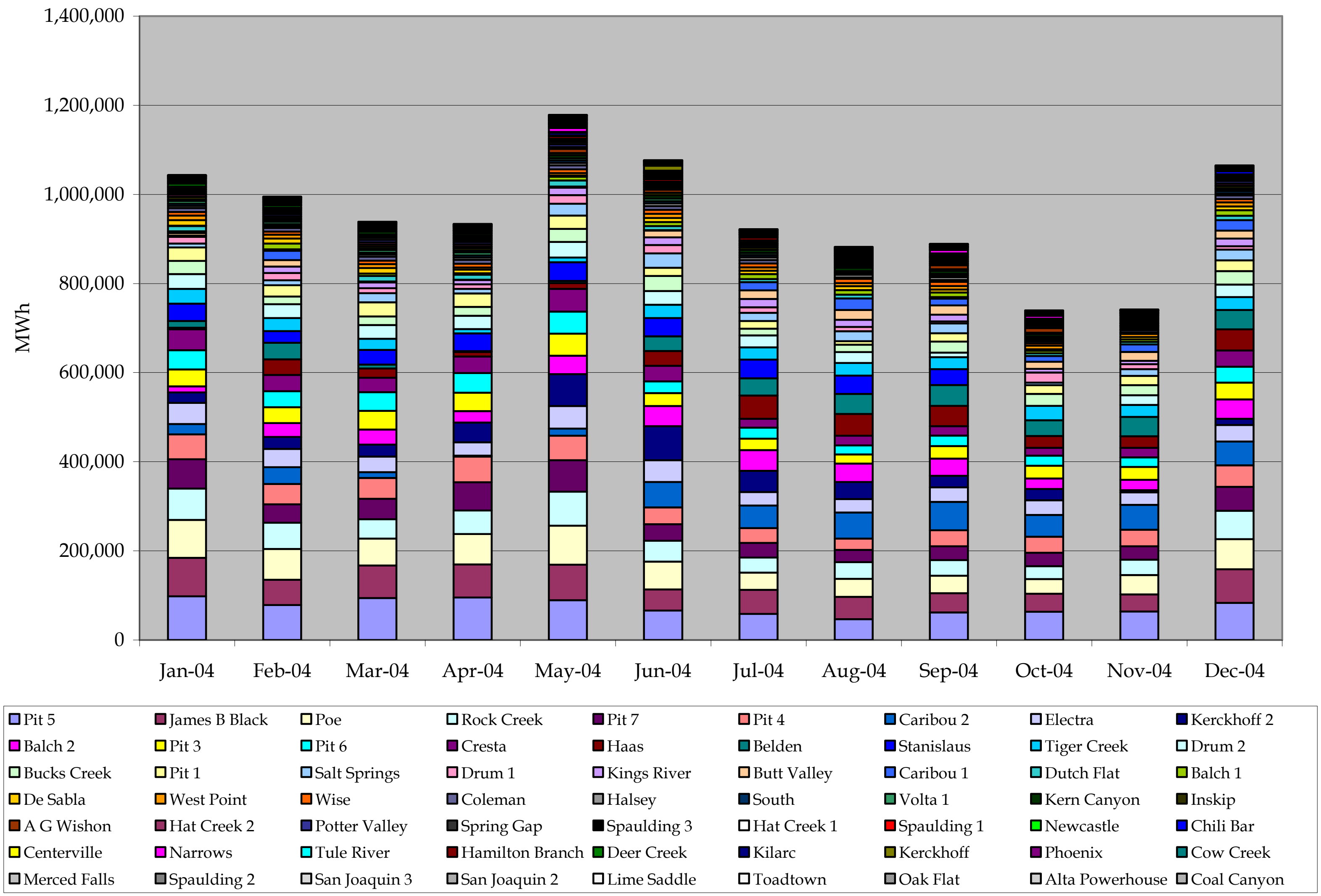


Figure 9 and Figure 10 highlight the mean monthly aggregate conventional hydroelectric production over the last ten years for SCE and PG&E, respectively, along with the 10% and 90% percentile monthly production levels (from the ten-year observation sample). This type of information on long run average seasonality trends in production would typically be used by market participants to understand the impact of "normalized" or average hydrological conditions, as well as "wet" and "dry" conditions, on electricity production and an IOU's buy and sell strategies. The monthly production data for each plant operated by SCE and PG&E over the last 10 years are presented in Appendices 1 and 2 respectively.

Figure 9. Mean monthly conventional hydroelectric power plant production for SCE over last ten years with 10%/90% percentile observations (excluding pumped storage)

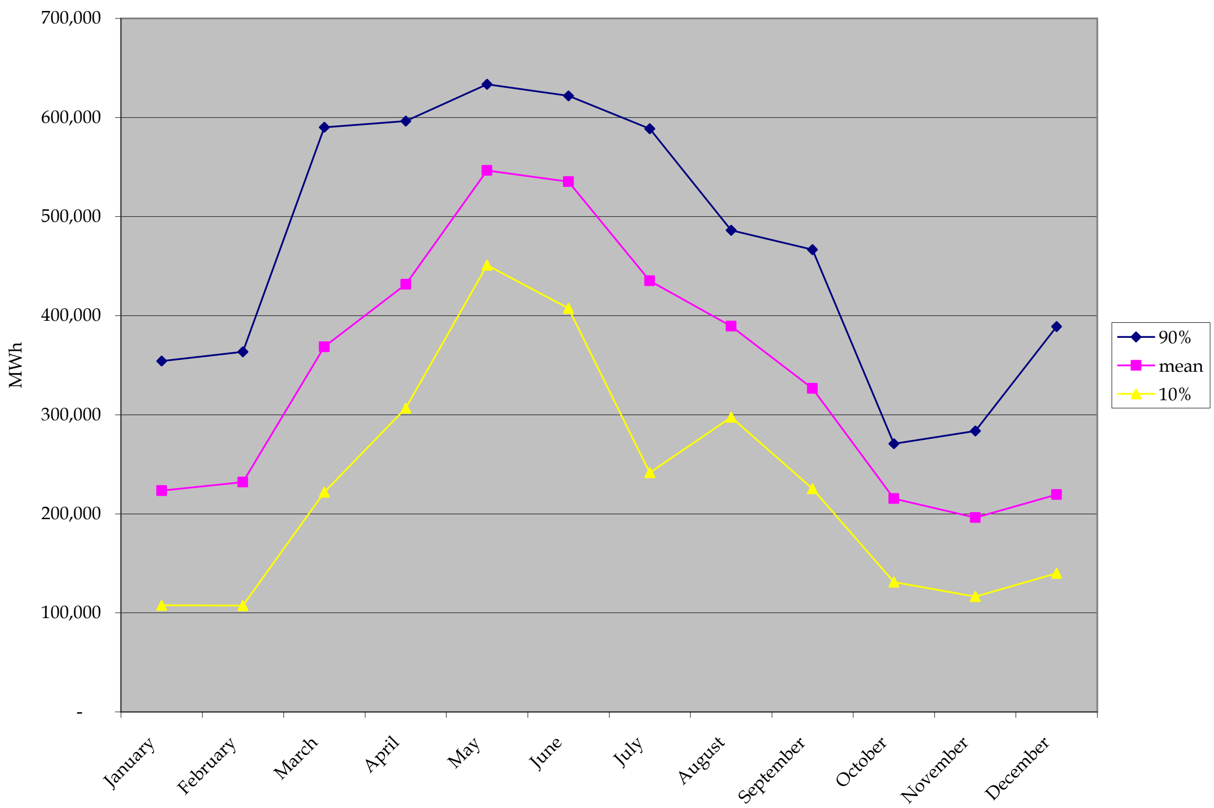


Figure 10. Mean monthly conventional hydroelectric power plant production for PG&E over last ten years with 10%/90% percentile observations

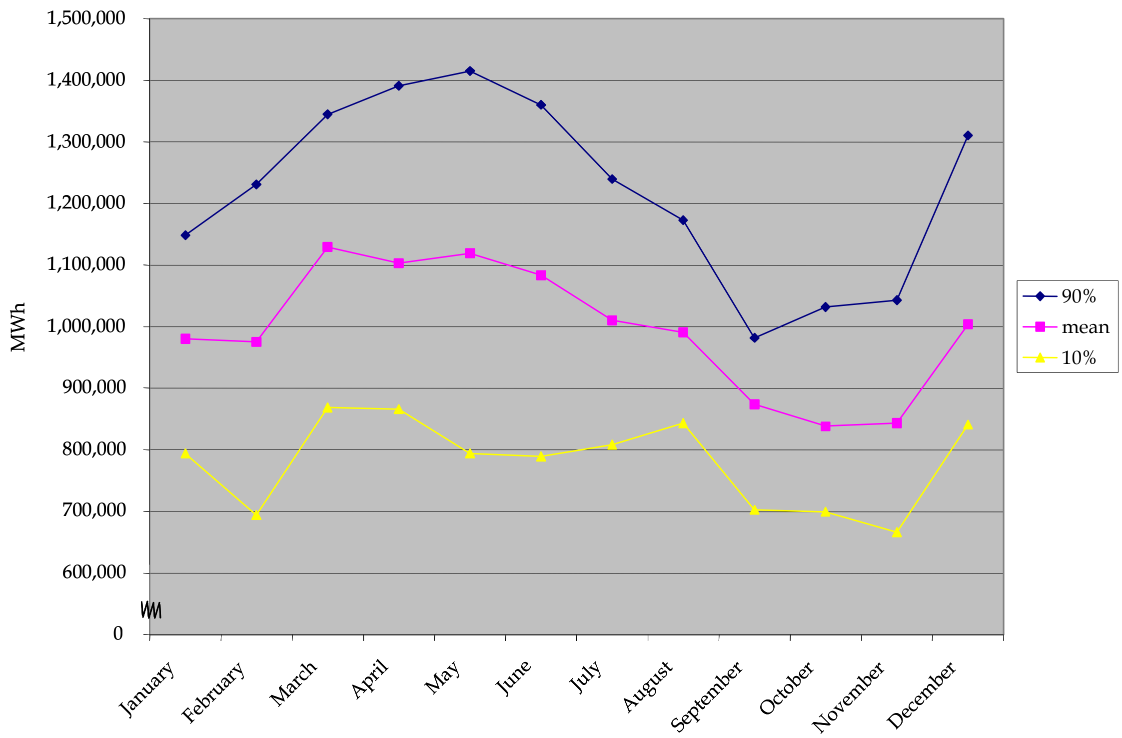
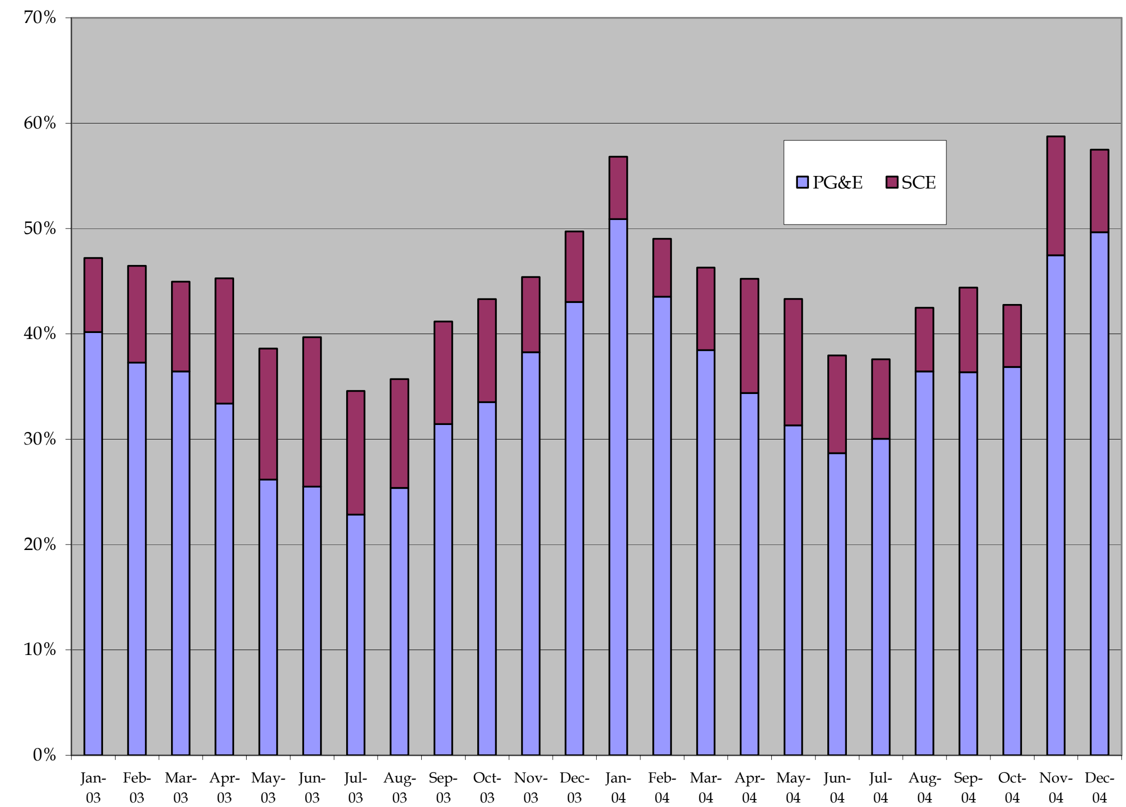


Figure 11 highlights the share of the two IOUs' total reported (conventional) hydroelectric monthly production as a function of total monthly submissions for California by all reporting entities. It shows that the two IOUs together account for 40% to nearly 60% of the total reported monthly hydroelectric generation for California (if one were to incorporate the two IOUs' pumped storage units, the percentage would increase). This observation underscores the relative significance of the IOUs' hydro production to the state as a whole.

Figure 11. Monthly conventional hydroelectric generation share for PG&E and SCE out of total monthly hydroelectric generation reported in California



Appendix 1: Monthly production data for each conventional hydroelectric plant operated by SCE (January 1996 – April 2005)

Year	1996
Plant Operator Name	SCE

Monthly Net Generation, MWh	Month												
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
Big Creek 1	48,197	18,742	42,193	58,286	65,756	42,264	57,331	60,446	46,655	20,758	27,333	51,292	539,253
Big Creek 2	43,748	16,099	38,330	48,956	49,784	37,170	48,920	46,663	39,000	18,398	23,880	44,550	455,498
Big Creek 2a	48,041	48,856	72,485	69,953	41,077	50,769	55,033	54,843	53,252	50,112	48,957	51,051	644,429
Big Creek 3	60,599	54,457	115,668	128,705	125,387	105,419	114,324	86,619	72,630	39,278	47,236	99,869	1,050,191
Big Creek 4	29,870	49,240	72,334	72,352	73,236	71,310	60,559	43,721	41,065	13,721	26,528	54,131	608,067
Big Creek 8	33,743	24,366	37,273	45,803	41,026	32,804	36,987	38,080	32,522	22,269	16,355	17,213	378,441
Bishop Creek 2	3,268	3,865	4,652	4,992	5,556	5,738	5,608	5,372	4,369	1,586	2,345	2,530	49,881
Bishop Creek 3	2,730	3,407	4,099	4,191	5,301	5,485	5,593	1,555	3,925	1,444	2,082	2,257	42,069
Bishop Creek 4	4,324	4,772	5,680	5,718	6,254	5,969	6,247	6,191	5,420	2,328	3,336	3,659	59,898
Bishop Creek 5	1,460	1,752	2,151	2,504	2,936	2,953	3,101	2,842	2,058	1,047	1,111	1,343	25,258
Bishop Creek 6	1,096	1,212	1,423	1,444	1,544	1,500	1,564	1,555	1,361	832	884	966	15,381
Borel	5,357	5,147	7,266	7,180	7,113	7,015	7,095	7,019	6,947	7,130	5,881	6,358	79,508
Fontana (CA)	597	394	591	857	612	448	460	431	599	620	575	525	6,709
Kaweah 1	1,379	1,225	1,401	1,375	1,286	627	1,142	1,148	828	467	845	1,197	12,920
Kaweah 2	1,269	1,357	1,498	1,405	1,417	1,430	1,515	695	229	121	725	100	11,761
Kaweah 3	2,663	2,893	3,248	2,742	2,981	2,898	2,926	1,692	703	534	1,668	2,999	27,947
Kern River 1	14,280	15,193	16,540	17,287	18,329	18,052	18,172	17,664	17,169	17,855	16,796	16,684	204,021
Kern River 3	14,010	22,997	26,574	26,261	25,286	25,645	27,081	10,713	6,987	6,655	14,856	3,266	210,331
Lundy	14	933	1,382	936	1,729	2,087	2,207	1,701	465	424	392	571	12,841
Lytle Creek	327	280	298	388	354	303	314	281	433	234	243	161	3,616
Mammoth Pool	20,995	65,046	125,361	119,671	119,998	116,933	101,547	58,159	39,964	10,379	17,232	71,902	867,187
Mill Creek	834	504	1,826	1,352	1,306	1,133	944	760	781	148	472	532	10,592
Mill Creek 1	409	347	173	325	425	440	368	331	353	230	226	104	3,731
Ontario 1	261	244	503	541	588	450	407	301	269	240	258	304	4,366
Ontario 2	103	99	250	192	237	184	161	124	113	101	96	98	1,758
Poole	2,585	2,548	3,589	1,563	5,221	7,450	7,267	4,096	1,256	1,554	2,285	2,519	41,933
Portal	565	5,263	6,989	5,847	1,821	4,735	5,252	5,656	4,960	2,518	2,665	4,466	50,737
Rush Creek	3,462	3,254	3,927	5,864	8,383	6,009	6,313	6,876	6,982	6,786	6,088	2,782	66,726
San Gorgonio Hydro	279	180	288	225	336	188	195	189	188	142	152	112	2,474
Santa Ana 1	510	805	1,760	1,568	1,221	1,122	1,324	1,100	662	554	572	679	11,877
Santa Ana 2	456	490	849	757	556	498	602	502	314	260	347	365	5,996
Santa Ana 3	485	504	938	698	413	383	421	383	45	7	132	(1)	4,408
Sierra	197	176	452	508	360	314	320	224	180	147	142	165	3,185
Tule River	1,777	1,657	1,871	1,816	1,907	1,768	1,768	1,245	1,017	1,276	1,403	1,602	19,107
Grand Total	**349,890**	**358,304**	**603,862**	**642,262**	**619,736**	**561,493**	**583,068**	**469,177**	**393,701**	**230,155**	**274,098**	**446,351**	**5,532,097**

Year	1997
Plant Operator Name	SCE

Monthly Net Generation, MWh	Month												
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
Big Creek 1	50,468	25,012	67,956	75,958	59,986	67,150	59,965	60,686	55,025	43,802	27,296	34,718	628,022
Big Creek 2	37,047	16,984	50,942	50,925	52,832	49,289	49,851	50,122	44,842	26,929	33,151	30,805	493,719
Big Creek 2a	31,264	14,539	36,646	34,792	54,410	71,157	73,528	73,750	70,015	59,788	35,546	27,563	582,998
Big Creek 3	4,085	5,197	110,266	122,281	130,667	125,879	94,526	86,472	89,859	49,239	39,015	40,995	898,481
Big Creek 4	71,714	36,773	71,824	66,103	71,313	70,219	47,534	44,862	44,150	24,376	20,218	20,726	589,812
Big Creek 8	11,588	5,179	36,523	41,594	47,577	47,238	46,110	44,017	41,608	33,911	19,931	20,157	395,433
Bishop Creek 2	4,266	4,490	4,553	3,042	5,092	5,515	5,716	4,985	3,355	3,757	3,375	2,866	51,012
Bishop Creek 3	3,758	3,875	4,379	2,736	4,528	5,611	5,793	4,764	3,251	2,997	2,938	2,382	47,012
Bishop Creek 4	5,307	5,256	5,564	3,902	5,646	5,748	5,895	5,578	4,622	4,642	4,058	3,548	59,766
Bishop Creek 5	2,045	2,178	2,288	1,436	2,502	2,760	2,160	2,048	1,621	1,489	1,409	1,362	23,298
Bishop Creek 6	936	1,372	1,524	1,032	1,460	1,466	1,512	1,436	1,166	903	1,117	1,019	14,943
Borel	7,400	6,584	7,497	6,701	7,891	6,892	7,192	7,137	6,922	1,850	(2)	(10)	66,054
Fontana (CA)	752	870	708	702	588	466	483	471	352	496	370	499	6,757
Kaweah 1	76	620	1,145	352		761	1,196	1,196	1,036	899	899	1,113	9,293
Kaweah 2	659	1,362	35	1,407	1,475	1,457	1,397	735	470	413	624	1,224	11,258
Kaweah 3	219						(8)	472	1,070	923	1,296	2,383	6,355
Kern River 1	18,983	16,372	17,830	16,723	18,557	17,734	18,257	17,624	17,667	16,559	11,082	18,339	205,727
Kern River 3	22,760	24,246	26,426	24,866	26,907	25,102	27,459	14,107	5,839	6,857	10,055	2,470	217,094
Lundy	1,557	1,327	798	1,080	2,040	2,181	2,227	2,024	811	582	358	256	15,241
Lytle Creek	111	242	238	257	269	225	239	262	192	250	192	176	2,653
Mammoth Pool	118,204	48,259	123,265	116,719	123,522	118,513	53,755	31,969	49,159	18,554	18,726	15,213	835,858
Mill Creek	902	1,117	1,577	1,699	1,306	827	838	794	122	709	436	503	10,830
Mill Creek 1	240	456	499	446			11	(1)			20	193	1,864
Ontario 1	502	517	518	382	444	316	283	236	180	195	200	129	3,902
Ontario 2	203	210	230	213	160	129	118	103	80	74	87	69	1,676
Poole	5,415	1,766	3,666	4,611	7,149	7,143	7,452	4,042	1,910	2,059	1,169	462	46,844
Portal	300	(17)	6,316	5,648	743	(13)	(10)	(9)	(3)	8,530	3,011	737	25,233
Rush Creek	6,806	5,138	3,307	3,736	6,587	6,392	7,846	8,179	7,404	5,739	3,949	2,490	67,573
San Gorgonio Hydro	92	64	38	149	150	101	92	135	179	143	114	154	1,411
Santa Ana 1	1,131	1,488	1,198	1,136	867	514	3	341	217	535	460	515	8,405
Santa Ana 2	546	783	620	567	475	290	210	199	151	306	279	333	4,759
Santa Ana 3	547	809	540	450	325	94	(3)	(3)	(3)	76	65	77	2,974
Sierra	373	448	434	421	343	264	228	158	115	99	93	97	3,073
Tule River	1,124	1,611	1,786	1,813	1,842	1,701	1,681	1,533	1,091			(6)	14,176
Grand Total	**411,380**	**235,127**	**591,136**	**593,879**	**637,653**	**643,121**	**523,536**	**470,424**	**454,475**	**317,681**	**241,537**	**233,557**	**5,353,506**

London Economics International LLC
717 Atlantic Ave, Suite 1A
Boston, MA 02111
www.londoneconomics.com

Year	1998
Plant Operator Name	SCE

Monthly Net Generation, MWh	Month												
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
Big Creek 1	40,727	49,329	33,521	40,706	58,071	53,955	58,090	64,679	54,261	54,261	25,620	38,170	571,390
Big Creek 2	32,397	38,043	25,510	30,658	44,114	41,999	46,830	47,047	46,599	19,600	34,075	38,326	445,198
Big Creek 2a	32,727	45,300	64,859	47,150	40,518	48,235	81,964	64,272	68,844	32,920	65,454	65,298	657,541
Big Creek 3	56,689	90,133	114,672	111,810	126,554	115,694	111,545	99,551	99,197	34,262	57,655	77,105	1,094,867
Big Creek 4	31,589	57,075	59,520	65,749	68,720	68,549	71,111	57,647	53,603	19,988	26,205	33,413	613,169
Big Creek 8	23,670	34,972	35,490	33,357	38,948	42,172	49,018	43,254	40,991	15,620	24,071	26,047	407,610
Bishop Creek 2	2,864	2,614	2,999	2,775	2,946	4,876	6,137	5,071	4,645	2,704	3,130	3,444	44,205
Bishop Creek 3	2,482	2,255	2,606	2,827	2,823	4,751	5,843	5,578	4,501	2,556	2,797	3,038	42,057
Bishop Creek 4	3,756	3,550	4,046	4,291	4,184	5,491	6,125	6,034	5,404	3,774	4,164	4,455	55,274
Bishop Creek 5	1,407	1,251	1,408	1,460	1,531	1,495	2,169	2,585	2,370	1,243	1,311	1,696	19,926
Bishop Creek 6	1,017	822	1,068	1,107	1,114	1,435	1,514	1,493	1,397	949	991	1,165	14,072
Borel	(10)	2,515	5,974	8,352	6,458	6,737	7,229	7,682	7,463	7,658	5,746	5,188	70,992
Fontana (CA)	519	269	574	1,273	796	498	246	752	1,075	959	982	809	8,752
Kaweah 1	1,206	909	1,337	1,334	1,347	1,055	1,135	1,276	1,308	1,382	1,369	1,036	14,694
Kaweah 2	1,185	1,011	1,487	512	1,160	1,068	1,431	1,428	1,226	63	1,235	712	12,518
Kaweah 3	2,543	2,389	3,199	3,135	3,195	3,159	3,293	3,095	2,753	1,985	2,288	2,477	33,511
Kern River 1	15,403	16,597	13,769	19,554	18,692	17,999	18,614	18,644	17,735	17,952	16,645	17,946	209,550
Kern River 3	16,189	23,782	2,486	28,832	26,590	25,650	25,648	26,517	19,514	3,587	13,640	12,943	225,378
Lundy	535	298	346	1,133	1,239	1,646	2,186	2,180	1,303	838	598	358	12,660
Lytle Creek	191	148	230	375	314	48	86	365	389	354	369	340	3,209
Mammoth Pool	24,172	46,007	89,671	71,110	120,858	106,056	92,579	73,796	65,150	14,272	26,483	30,537	760,691
Mill Creek	683	325	801	1,196	756	1,602	1,759	1,020	1,373	1,367	1,387	1,259	13,528
Mill Creek 1	394	180	374	441	300	624	866	250	341	773	788	758	6,089
Ontario 1	216	163	294	537	157	558	528	503	549	425	384	335	4,649
Ontario 2	88	78	165	261	80	285	258	232	243	168	162	124	2,144
Poole	1,529	1,551	2,031	2,920	2,953	7,626	8,288	5,262	2,777	1,910	2,397	1,406	40,650
Portal	4,423	1,782	1,718	6,702	5,811	3,378	3,987	5,073	5,496	5,496	3,252	1,514	48,632
Rush Creek	2,446	2,164	3,665	3,102	5,683	7,626	8,098	8,156	7,702	6,931	3,944	4,137	63,654
San Gorgonio Hydro	80	96	63	133	417	25	503	449	95	(2)	(3)	(5)	1,851
Santa Ana 1	743	211	1,240	2,037	377	1,332	1,735	1,400	1,086	922	417	1,126	12,626
Santa Ana 2	396	157	616	990	394	931	867	624	484	347			5,806
Santa Ana 3	300	146	622	1,005	176								2,249
Sierra	145	135	288	465	141	517	472	424	461	322	377	212	3,959
Tule River	881	1,443	1,895	1,761	1,540	1,828	1,890	1,842	1,797	1,878	1,813	1,874	20,442
Grand Total	**303,582**	**427,700**	**478,544**	**499,050**	**588,957**	**578,900**	**622,044**	**558,181**	**522,132**	**257,464**	**329,746**	**377,243**	**5,543,543**

Year	1999
Plant Operator Name	SCE

Monthly Net Generation, MWh	Month												
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
Big Creek 1	30,437	16,938	28,944	17,701	33,101	44,060	52,845	56,791	51,700	26,738	14,121	17,603	390,979
Big Creek 2	25,904	15,821	24,735	17,377	31,043	37,138	44,370	47,540	34,457	30,109	13,200	15,519	337,213
Big Creek 2a	22,169	21,903	27,667	46,105	26,634	62,253	74,186	58,186	52,021	44,884	42,723	41,491	520,222
Big Creek 3	42,339	65,823	66,486	88,823	120,200	124,149	80,431	87,583	68,801	43,951	22,273	28,815	839,674
Big Creek 4	27,476	31,283	32,802	46,360	62,383	70,142	40,106	44,363	37,343	18,415	10,011	15,185	435,869
Big Creek 8	16,586	13,434	17,813	22,127	21,467	35,448	38,684	41,694	30,385	25,571	27,355	8,495	299,059
Bishop Creek 2	2,802	2,163	2,216	2,423	3,762	4,738	5,269	4,034	3,173	2,665	2,645	2,341	38,231
Bishop Creek 3	2,473	1,852	1,971	2,507	3,388	4,369	4,884	3,648	2,940	2,430	2,217	2,030	34,709
Bishop Creek 4	4,062	1,942	3,195	3,434	5,623	5,117	5,603	5,234	4,117	3,409	2,955	1,208	45,899
Bishop Creek 5	1,076	1,016	1,066	1,257	1,814	2,348	2,762	1,833	1,589	1,152	1,138	1,070	18,121
Bishop Creek 6	1,028	753	827	946	1,266	1,322	1,446	1,226	1,130	949	619	847	12,359
Borel	5,561	6,342	5,559	5,452	7,325	7,491	7,529	7,628	5,217	(2)	1,241	2,760	62,103
Fontana (CA)	687	696	712	671	584	559	401	333	321	301	373	357	5,995
Kaweah 1	1,228	1,053	1,209	1,331	1,411	1,395	1,295	883	400	(1)	448	415	11,067
Kaweah 2	851	1,130	1,443	1,359	1,489	1,434	1,120	148		(1)	(1)	(1)	8,971
Kaweah 3	1,963	79	(5)	1,752	2,719	3,052	2,055	541	312	97	442	375	13,382
Kern River 1	17,486	16,232	16,826	17,263	18,516	17,887	17,918	17,284	16,369	14,476	7,360	10,630	188,247
Kern River 3	12,172	13,736	13,844	17,295	26,027	24,111	13,561	1,675	(16)	(13)	(15)	2,032	124,409
Lundy	353	886	362	358	1,757	1,787	2,193	1,259	366	162	166	396	10,045
Lytle Creek	336	305	396	315	330	257	169	177	153	134	183	186	2,941
Mammoth Pool	24,061	44,454	60,278	66,848	115,638	121,162	44,687	50,627	41,499	25,357	1,544	8,186	604,341
Mill Creek	1,116	967	1,068	915	951	799	204	466	421	527	601	549	8,584
Mill Creek 1	697	637	734	639	779	341	133	239	313	349	158	337	5,356
Ontario 1	293	283	276	246	287	256	146	180	132	118	130	93	2,440
Ontario 2	119	117	125	110	135	131	72	79	67	61	70	61	1,147
Poole	1,321	857	744	1,497	6,033	7,276	5,751	2,405	1,426	1,364	1,716	1,454	31,844
Portal	1,972	2,618	2,506	2,322	5,108	2,768	4,380	6,424	4,868	1,575	1,566	1,677	37,784
Rush Creek	4,126	3,873	4,114	2,184	4,107	4,526	8,090	2,799	3,484	7,654	5,426	4,203	54,586
San Gorgonio Hydro	(2)	(5)	(2)	(6)	(1)	(3)	(1)	(1)	(1)	(1)		(2)	(25)
Santa Ana 1	1,231	1,225	1,258	1,238	1,072	811	433	466	370	490	531	531	9,656
Santa Ana 3						1	178	52	49	115	453	322	1,170
Sierra	252	234	217	181	254	217	93	73	80	63	75	53	1,792
Tule River	1,850	1,679	1,892	1,794	1,845	1,623	1,363	1,016	839	1,043	1,192	1,243	17,379
Grand Total	**254,025**	**270,326**	**321,278**	**372,824**	**507,047**	**588,965**	**462,356**	**446,885**	**364,325**	**254,141**	**162,916**	**170,461**	**4,175,549**

London Economics International LLC
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Year	2000
Plant Operator Name	SCE

Monthly Net Generation, MWh	Month												
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
Big Creek 1	13,411	5,643	21,792	44,758	62,777	62,280	48,955	40,739	31,046	36,818	35,998	13,497	417,714
Big Creek 2	3,370	5,643	28,499	40,763	50,317	48,454	40,073	33,727	28,134	30,153	31,253	12,557	352,943
Big Creek 2a	12,101	10,175	44,824	46,873	62,751	66,743	58,257	47,486	43,697	54,047	41,934	25,015	513,903
Big Creek 3	20,282	36,403	114,310	118,962	131,062	120,704	88,190	64,352	44,816	43,767	31,903	22,792	837,543
Big Creek 4	12,494	22,830	53,025	65,078	71,310	69,070	45,814	34,487	23,177	21,334	21,555	8,636	448,810
Big Creek 8	4,928	5,891	26,695	31,951	42,111	44,108	33,504	28,141	23,202	29,381	24,422	11,352	305,686
Bishop Creek 2	1,570	1,978	3,392	3,165	3,861	4,827	4,807	4,012	2,939	1,488	1,508	2,508	36,055
Bishop Creek 3	1,370	1,767	3,086	2,829	3,626	4,513	4,461	3,732	2,427	1,416	1,520	2,274	33,021
Bishop Creek 4	2,543	2,845	4,243	4,165	5,023	5,621	5,697	5,172	3,598	2,890	2,577	3,484	47,858
Bishop Creek 5	752	360	1,688	951	1,819	2,443	2,343	1,754	1,112	766	877	1,194	16,059
Bishop Creek 6	692	787	1,149	1,069	1,294	1,182	1,434	1,197	863	471	608	819	11,565
Borel	3,981	4,194	6,153	7,337	8,010	7,814	7,839	7,542	5,464	4,204	1,854	2,974	67,366
Fontana (CA)	398	295	641	564	525	346	311	241	240	307	317	368	4,553
Kaweah 1	585	870	1,391	1,385	1,443	1,311	1,142	550	595	12	735	729	10,748
Kaweah 2	553	1,401	1,560	1,520	1,554	1,520	1,101	173		(1)	485	371	10,237
Kaweah 3	906	2,542	3,249	3,173	3,317	3,185	2,037	500	(1)	44	1,598	897	21,447
Kern River 1	11,524	13,897	13,487	17,923	16,398	17,970	17,602	15,097	11,295	457	2,476	(9)	138,117
Kern River 3	5,335	11,837	19,345	24,315	26,073	25,104	10,517	2,158	1,218	2,226	4,567	4,031	136,726
Lundy	154	195	411	675	2,054	2,044	1,557	768	408	276	300	322	9,164
Lytle Creek	203	112	246	230	236	140	105	72	83	125	146	156	1,854
Mammoth Pool	1,835	28,141	93,419	105,342	121,488	109,548	63,003	41,847	21,901	8,892	8,977	12,138	616,531
Mill Creek	545	281	375	348	1,258	850	740	505	527	673	527	(1)	6,628
Mill Creek 1	376	165	198	134	598	453	431	272	247	401	331	308	3,914
Ontario 1	135	62	19	53									269
Ontario 2	53		(1)	16	205	141	116		50	77	37		694
Poole	1,160	1,317	306	2,300	6,102	6,960	4,026	1,858	786	1,465	1,777	1,732	29,789
Portal	264	(8)	4,754	6,008	3,541	1,979	5,507	6,074	3,527	9,948	488	4,315	46,397
Rush Creek	1,810	2,083	4,092	2,574	2,025	6,627	6,786	2,722	5,429	6,671	7,197	4,620	52,636
San Gorgonio Hydro	(9)	(2)	(20)	(2)	(6)							(4)	(43)
Santa Ana 1	643	209	876	1,056	1,058	576	430	353	410	520	411	668	7,210
Santa Ana 3	666	398	162	988	1,050	314	(6)	(5)	(5)	156	351	304	4,373
Sierra	44	(1)		27	345	250	176	77	86	119	101	40	1,264
Tule River	1,031	1,559	1,856	1,812	1,415	1,740	1,316	764	704	1,079	1,280	1,229	15,785
Grand Total	**105,705**	**163,869**	**455,222**	**538,342**	**634,640**	**618,817**	**458,271**	**346,367**	**257,975**	**260,182**	**228,110**	**139,316**	**4,206,816**

Year	2001
Plant Operator Name	SCE

Monthly Net Generation, MWh	Month											
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
Big Creek 1	11,474	649	3,934	4,731	46,614	46,854	27,113	36,174	34,266	52,187	26,415	17,246	307,657
Big Creek 2	11,018	305	6,079	6,598	41,491	37,765	23,793	40,222	19,117	15,636	8,813	16,152	226,989
Big Creek 2a	16,163	3,156	6,357	7,709	45,495	55,903	32,066	45,325	40,620	14,520	4,718	8,056	280,088
Big Creek 3	16,637	9,176	48,439	83,989	129,171	80,064	42,680	62,345	42,416	20,900	12,590	22,396	570,803
Big Creek 4	9,289	6,184	25,764	42,695	69,150	42,463	21,608	32,611	24,380	8,013	5,962	13,097	301,216
Big Creek 8	7,536	213	3,606	3,323	31,624	33,819	16,760	26,796	24,070	10,838	4,744	10,967	174,296
Bishop Creek 2	1,646	1,091	1,597	2,197	4,336	4,883	4,915	3,733	2,878	2,626	1,566	2,930	34,398
Bishop Creek 3	1,510	1,129	1,534	2,029	4,063	4,341	4,552	3,363	2,622	2,134	1,396	2,597	31,270
Bishop Creek 4	2,578	1,886	2,755	3,024	5,389	5,532	5,696	4,747	3,849	2,986	1,258	3,827	43,527
Bishop Creek 5	728	552	1,254	575	1,880	3,323	1,105	1,449	1,271	1,156	-	-	13,293
Bishop Creek 6	640	523	670	825	1,041	1,366	865	1,116	976	815	-	(7)	8,830
Borel	2,492	3,328	5,337	5,958	7,320	7,693	7,755	7,591	4,227	3,199	2,473	3,728	61,101
Catalina Micro Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-
Fontana (CA)	337	196	833	769	667	460	393	336	288	376	401	409	5,465
Kaweah 1	825	1,004	1,113	1,247	1,401	1,340	1,023	281	383	44	492	1,246	10,399
Kaweah 2	329	1,184	1,454	1,510	1,586	1,418	675	-	-	-	(1)	1,142	9,297
Kaweah 3	845	2,153	2,845	3,148	3,302	2,909	1,505	59	(1)	(1)	1,137	2,654	20,555
Kern River 1	6,352	11,988	16,939	17,487	17,955	17,666	17,785	17,783	14,326	10,732	6,125	12,194	167,332
Kern River 3	4,432	6,121	14,458	21,196	25,732	9,653	8,368	354	110	43	3,685	9,463	103,615
Lundy	218	226	339	1,219	1,183	1,633	967	902	468	151	145	146	7,597
Lytle Creek	115	41	387	383	344	228	195	171	154	214	201	191	2,624
Mammoth Pool	5,187	7,322	46,197	85,632	122,294	69,199	14,015	38,246	14,103	7,908	6,965	11,884	428,952
Mill Creek	235	526	624	589	368	622	560	556	426	501	387	453	5,847
Mill Creek 1	285	412	459	306	215	325	278	260	231	280	210	226	3,487
Ontario 1	-	-	-	170	515	481	384	282	212	232	45	-	2,321
Ontario 2	55	74	170	286	280	194	152	131	100	102	88	85	1,717
Poole	1,144	1,049	1,201	2,237	7,308	3,828	824	835	455	1,230	1,847	1,167	23,125
Portal	2,278	830	2,092	2,986	4,963	4,776	4,982	5,797	5,306	2,351	186	926	37,473
Rush Creek	2,335	981	1,070	1,192	3,552	3,948	5,281	421	3,988	4,380	4,783	4,991	36,922
San Gorgonio Hydro	(3)	(2)	(4)	(1)	(1)	-	-	-	-	-	(1)	(2)	(14)
Santa Ana 1	556	701	1,126	1,081	744	428	290	233	254	335	381	483	6,612
Santa Ana 3	607	896	1,305	1,176	680	150	(4)	(5)	(5)	(5)	119	472	5,386
Sierra	77	96	245	426	502	238	291	234	174	183	(1)	39	2,504
Tule River	1,160	1,520	1,835	1,715	1,806	1,412	870	481	311	(2)	(4)	(7)	11,097
Grand Total	**109,080**	**65,510**	**202,014**	**308,407**	**582,970**	**444,914**	**247,742**	**332,829**	**241,975**	**164,064**	**97,125**	**149,151**	**2,945,781**

Year	2002
Plant Operator Name	SCE

Monthly Net Generation, MWh	Month											
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
Big Creek 1	22,223	18,613	6,450	8,192	34,794	41,197	33,696	41,315	30,568	16,785	11,027	9,130	273,990
Big Creek 2	20,416	17,495	9,014	9,461	38,404	44,409	35,880	43,558	31,949	14,660	10,080	7,843	283,169
Big Creek 2a	34,528	46,096	18,511	8,616	37,727	60,438	50,338	59,237	46,552	18,563	11,969	21,368	413,943
Big Creek 3	52,512	52,304	55,181	93,681	108,812	106,046	56,705	66,766	49,793	25,379	21,948	29,380	718,507
Big Creek 4	29,305	22,712	25,266	46,347	54,695	55,195	28,481	33,247	23,833	10,882	10,013	14,199	354,175
Big Creek 8	19,923	22,580	7,261	5,896	26,226	37,680	30,057	36,860	27,421	10,849	7,332	9,375	241,460
Bishop Creek 2	2,724	2,154	1,667	2,269	3,302	3,739	3,163	2,994	1,374	-	-	1,286	24,672
Bishop Creek 3	2,371	1,865	1,391	1,924	2,907	3,228	2,838	2,613	2,480	1,657	978	1,392	25,644
Bishop Creek 4	3,576	2,933	2,476	3,151	3,681	4,751	4,293	3,950	3,851	2,848	2,173	2,458	40,141
Bishop Creek 5	-	-	-	-	681	1,509	1,230	1,277	1,230	692	564	620	7,803
Bishop Creek 6	536	599	(14)	(10)	511	1,081	919	943	907	365	514	558	6,909
Borel	4,825	4,002	5,612	5,899	6,837	6,759	7,259	6,523	1,941	36	2,385	4,542	56,620
Catalina Micro Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-
Fontana (CA)	475	431	417	353	307	227	179	161	131	153	188	258	3,280
Kaweah 1	1,256	1,096	1,246	1,320	1,372	1,296	1,111	598	278	225	474	1,264	11,536
Kaweah 2	1,357	1,336	1,511	1,477	1,527	1,463	975	27	(2)	-	495	1,569	11,735
Kaweah 3	3,013	2,752	3,244	3,137	3,212	3,107	1,884	168	(3)	99	1,775	2,644	25,032
Kern River 1	15,547	10,848	18,309	17,233	18,227	17,399	13,593	15,454	10,200	9,140	11,719	7,389	165,058
Kern River 3	1,561	7,787	13,340	24,155	24,559	23,353	7,798	249	96	423	4,715	9,282	117,318
Lundy	176	514	701	191	1,235	1,888	1,183	576	330	338	325	278	7,735
Lytle Creek	274	231	237	196	121	114	85	69	61	77	92	140	1,697
Mammoth Pool	31,281	25,461	45,868	97,199	96,370	88,438	25,732	26,784	18,384	9,174	7,906	14,440	487,037
Mill Creek	500	406	527	455	426	288	301	281	277	319	304	170	4,254
Mill Creek 1	331	292	252	203	136	139	136	120	100	108	73	93	1,983
Ontario 1	41	183	213	201	171	57	135	101	70	105	114	169	1,560
Ontario 2	93	76	69	69	58	38	51	44	31	27	35	60	651
Poole	948	1,161	1,434	3,087	5,308	7,285	3,648	1,237	301	103	1,814	1,160	27,486
Portal	1,111	1,249	1,969	5,123	5,065	4,511	6,203	6,468	3,902	2,556	619	547	39,323
Rush Creek	4,848	4,587	5,387	3,724	2,860	1,743	1,714	1,268	3,248	6,588	5,057	3,472	44,496
San Gorgonio Hydro	(2)	(3)	(2)	(2)	(2)	(1)	-	-	-	-	-	-	(12)
Santa Ana 1	574	496	560	436	404	225	148	109	141	2	283	497	3,875
Santa Ana 3	506	354	356	201	10	(8)	(9)	(8)	(8)	(8)	278	454	2,118
Sierra	181	143	131	127	88	59	78	66	46	59	60	102	1,140
Tule River	1,298	1,623	1,835	1,713	1,815	1,681	957	550	420	776	842	678	14,188
Grand Total	**258,308**	**252,376**	**230,419**	**346,024**	**481,846**	**519,334**	**320,761**	**353,605**	**259,902**	**132,980**	**116,151**	**146,817**	**3,418,523**

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Year	2003
Plant Operator Name	SCE

Monthly Net Generation, MWh	Month											
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
Big Creek 1	8,723	25,518	13,656	13,181	44,205	59,139	54,591	43,464	39,391	32,658	21,866	19,354	375,746
Big Creek 2	7,640	22,352	14,137	14,028	39,781	47,464	45,394	36,048	32,866	27,113	16,160	15,402	318,385
Big Creek 2a	22,710	45,684	24,888	23,180	56,958	64,259	65,746	56,305	51,229	30,705	20,695	32,032	494,391
Big Creek 3	42,369	48,776	45,640	83,297	124,237	120,616	90,310	67,877	44,143	35,207	23,414	26,527	752,413
Big Creek 4	19,632	22,464	21,798	41,620	68,810	67,251	46,320	34,780	22,251	21,745	7,855	14,900	389,426
Big Creek 8	9,441	22,475	11,847	11,408	34,772	41,723	39,736	32,226	28,823	19,518	12,200	15,471	279,640
Bishop Creek 2	1,493	1,372	1,450	2,018	3,236	4,735	4,878	3,860	2,059	1,588	923	1,741	29,353
Bishop Creek 3	1,292	1,158	1,249	1,751	2,954	4,885	4,389	3,593	2,061	1,681	853	1,627	27,493
Bishop Creek 4	2,364	2,182	2,426	2,978	4,595	5,953	5,858	5,067	3,272	2,850	2,652	2,763	42,960
Bishop Creek 5	587	527	593	935	1,554	2,363	2,194	1,699	992	861	795	789	13,889
Bishop Creek 6	529	478	521	689	1,113	1,420	1,377	1,175	768	662	649	675	10,056
Borel	5,817	4,048	5,035	5,120	6,791	7,274	7,290	7,061	6,677	6,003	2,493	3,156	66,765
Fontana (CA)	228	164	520	545	573	393	279	229	206	228	243	313	3,921
Kaweah 1	1,297	1,190	997	1,138	1,276	1,241	1,260	1,186	899	360	708	961	12,513
Kaweah 2	1,416	1,259	1,443	1,376	1,493	1,383	1,312	618	131	(8)	315	986	11,724
Kaweah 3	3,170	2,844	3,217	3,142	3,372	3,165	2,820	1,377	484	183	676	1,982	26,432
Kern River 1	1,574	1,375	14,332	14,684	15,590	14,489	9,881	14,704	13,575	14,150	7,252	9,066	130,672
Kern River 3	13,093	12,152	13,126	22,607	22,144	21,381	14,153	1,265	(11)	198	3,568	3,783	127,459
Lundy	363	154	1,004	238	659	2,077	1,461	772	586	477	295	305	8,391
Mammoth Pool	29,289	21,405	29,782	78,981	111,100	107,277	56,479	35,818	12,007	12,433	10,027	8,388	512,986
Mill Creek	360	367	1,051	1,510	1,702	1,257	1,149	908	739	617	684	535	10,879
Poole	1,424	1,161	1,366	1,334	3,773	6,788	4,029	1,250	861	782	993	1,769	25,530
Portal	1,331	694	1,340	2,411	4,125	2,864	4,691	5,192	6,513	3,231	239	689	33,320
Rush Creek	3,498	3,161	3,518	1,475	1,123	6,107	5,575	1,432	3,920	1,375	768	800	32,752
San Gorgonio Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-
Santa Ana 1	534	467	1,082	676	947	605	338	189	214	158	137	196	5,543
Santa Ana 3	689	614	1,305	927	1,121	708	306	268	216	66	603	446	7,269
Tule River	1,845	1,464	1,737	1,746	1,904	1,770	1,712	1,228	655	1,005	1,303	1,491	17,860
Grand Total	**182,708**	**245,505**	**219,060**	**332,995**	**559,908**	**598,587**	**473,528**	**359,591**	**275,527**	**215,846**	**138,366**	**166,147**	**3,767,768**

Year	2004
Plant Operator Name	SCE

Monthly Net Generation, MWh	Month												
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
Big Creek 1	15,828	16,408	20,908	33,585	34,472	36,037	37,043	31,364	39,172	22,064	32,907	23,963	343,751
Big Creek 2a	29,051	19,586	20,448	19,187	39,477	37,448	47,362	34,498	44,459	31,313	42,765	36,325	401,919
Big Creek 3	38,675	34,797	78,592	104,704	96,185	30,548	66,069	45,944	40,665	24,628	53,946	39,737	654,490
Big Creek 4	23,065	21,223	40,381	47,136	50,565	84,691	32,587	22,507	18,956	15,395	20,738	20,333	397,577
Mammoth Pool	24,972	20,187	68,335	101,016	87,619	73,905	36,525	23,756	16,644	5,857	21,580	19,906	500,302
San Gorgonio Hydro	-	-	-	-	-	-	-	-					-
San Gorgonio Hydro 1									-	-	-	-	-
Grand Total	**131,591**	**112,201**	**228,664**	**305,628**	**308,318**	**262,629**	**219,586**	**158,069**	**159,896**	**99,257**	**171,936**	**140,264**	**2,298,039**

Year	2005
Plant Operator Name	SCE

Sum of Net Generation MWh	Month				
Plant Name	1	2	3	4	Grand Total
Big Creek 1	6634	2766	39181	63917	112498
Big Creek 2a	39355	13300	61992	70317	184964
Big Creek 3	40795	55564	109042	102515	307916
Big Creek 4	25217	38796	65513	64034	193560
Mammoth Pool	13879	79280	80346	79684	253189
Grand Total	125880	189706	356074	380467	1052127

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Appendix 2 : Monthly production data for each conventional hydroelectric plant operated by PG&E (January 1996 – April 2005)

Year	1996
Plant Operator Name	PG&E

Monthly Net Generation, MWh	Month												
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
A G Wishon	1,676	9,273	13,137	12,521	11,591	7,978	9,621	1,565	79	3,298	10,200	12,611	93,550
Alta (CA)	305	511	347	247	165	172	494	476	266	432	322	367	4,104
Balch 1	6,527	7,505	18,422	24,222	21,015	23,261	5,976	(4)	1,187	5,700	2,798	16,747	133,356
Balch 2	14,988	27,724	67,897	76,801	79,754	74,043	54,890	64,018	42,235	31,687	46,602	69,454	650,093
Belden	20,564	25,522	34,237	77,119	49,675	60,133	64,159	59,146	53,024	58,706	57,074	41,984	601,343
Bucks Creek	12,143	35,363	44,302	43,208	45,007	23,164	17,655	32,172	23,506	23,574	30,671	38,305	369,070
Butt Valley	8,526	2,041	10,402	23,535	3,140	2,676	16,712	16,351	16,232	16,535	14,521	11,861	142,532
Caribou 1	8,973	4,903	17,006	42,599	54,052	51,317	54,630	54,096	52,798	54,756	51,814	53,615	500,559
Caribou 2	22,696	30,061	33,522	69,197	(34)	(29)	(27)	(27)	(26)	(31)	(37)	(28)	155,237
Centerville (CA)	3,746	3,272	4,023	3,999	4,211	4,236	1,679	1,316	2,789	1,246	1,622	2,571	34,710
Chili Bar	3,060	6,193	5,909	5,869	6,148	4,686	2,311	2,262	2,471	1,462	1,993	5,591	47,955
Coal Canyon	555	438	631	622	635	551	569	522	527	457		101	5,608
Coleman (CA)	8,397	8,028	8,835	8,480	8,450	8,102	7,632	4,999	5,041	5,950	6,470	6,263	86,647
Cow Creek	1,111	632	994	1,454	1,503	1,427	912	645	621	722	969	1,387	12,377
Crane Valley	3	382	565	557	627	467	588	62		185	505	542	4,483
Cresta	34,060	49,127	53,545	51,794	53,039	43,475	34,189	31,145	27,063	29,446	35,811	44,302	486,996
De Sabla	11,649	11,163	13,126	13,576	13,893	13,350	7,618	4,559	9,212	7,391	8,252	11,448	125,237
Deer Creek (CA)	1,772	2,107	2,258	935	3,228	3,124	2,173	2,246	2,174	1,693	1,172	1,637	24,519
Drum 1	5,345	19,469	22,837	21,587	22,519	21,242	17,759	13,028	5,072	6,289	11,620	20,632	187,399
Drum 2	23,159	29,814	31,048	31,102	30,972	30,293	27,010	23,607	15,120	21,086	20,984	29,979	314,174
Dutch Flat	1,811	12,396	12,839	12,383	12,096	8,648	6,834	5,375	2,228	5,525	6,557	13,231	99,923
Electra (CA)	29,298	51,308	57,349	55,198	42,435	33,535	40,999	43,017	33,856	31,641	45,698	51,909	516,243
Haas	11,975	9,966	62,216	64,171	98,040	92,013	54,662	59,093	40,849	35,079	37,531	65,916	631,511
Halsey	5,928	3,540	4,576	374	5,866	6,281	6,312	6,507	6,406	4,153	4,671	5,724	60,338
Hamilton Branch	3,185	3,110	3,214	3,102	3,283	2,286	1,992	1,704	2,701	1,956	1,929	3,150	31,612
Hat Creek 1	3,491	699	3,902	3,703	3,272	3,067	2,647	2,607	2,527	3,137	3,585	3,977	36,614
Hat Creek 2	4,604	4,747	5,227	4,932	4,574	4,272	3,984	3,737	3,672	4,177	4,572	5,007	53,505
Inskip	5,450	5,217	5,642	5,470	5,590	5,486	5,259	3,689	3,740	4,211	4,391	4,769	58,914
James B Black	53,466	83,745	94,174	78,693	81,896	55,912	44,939	62,448	48,990	45,890	57,064	90,724	797,941
Kerckhoff	(31)	1,438	1,772	473	16,093	18,111	614	223	(30)	(29)	11,025	2,414	52,073
Kerckhoff 2	5,412	54,944	91,943	87,926	96,977	87,144	69,238	44,823	41,405	12,798	11,277	67,896	671,783
Kern Canyon	5,412	3,117	(8)	7,620	7,390	7,440	6,437	8,419		7,608	6,050		59,485
Kilarc	1,826	2,128	2,456	2,374	2,461	2,315	1,626	1,167	999	877	1,254	2,041	21,524
Kings River	5,940	11,090	28,991	33,284	35,512	31,218	16,631	19,844	12,478	10,276	15,633	29,777	250,674
Lime Saddle	792	707	876	805	847	824	826	794	766	661	290	348	8,536
Merced Falls	(12)	1,036	2,248	1,908	2,338	2,292	2,352	2,224	1,564	1,404	(12)	846	18,188
Narrows (CA)	1,872	7,490	7,608	8,021	8,418	2,603	(11)	5,317	5,130	1	(8)	5,054	51,495
Newcastle	6,507	3,715	4,905	1,074	2,659	1,545	3	243	3,320	2,387	4,766	6,517	37,641
Oak Flat	419	379	580	436	854	812	811	624	370	392	381	310	6,368
Phoenix	587	1,118	366	1,345	1,048	1,452	830	893	865	355	281	452	9,592
Pit 1	25,582	33,090	35,831	32,895	32,334	24,921	23,201	24,431	23,852	24,957	26,366	25,199	332,659
Pit 3	47,107	49,546	52,782	50,862	49,132	34,473	29,194	27,080	25,831	30,203	34,989	45,879	477,078
Pit 4	60,690	65,486	71,287	68,661	65,599	45,009	38,043	34,911	33,635	39,092	45,003	60,872	628,288
Pit 5	104,051	109,604	119,083	114,756	110,291	75,631	66,619	60,120	54,605	65,891	77,414	102,994	1,061,059
Pit 6	38,185	52,525	57,107	51,640	49,138	29,011	23,147	25,799	22,114	22,700	30,187	48,692	450,245
Pit 7	55,634	75,810	80,270	71,177	67,964	42,302	32,996	33,814	29,498	32,853	40,947	68,976	632,241
Poe	60,910	83,572	88,041	85,664	90,259	73,298	57,452	51,342	43,318	49,052	59,102	57,139	799,149
Potter Valley	5,624	8,132	6,629	6,464	6,242	4,501	3,509	3,903	6,160	6,226	4,179	5,801	67,370
Rock Creek	52,322	78,530	84,019	82,736	85,407	76,967	56,875	49,118	42,427	46,872	55,145	66,689	777,107
Salt Springs	12,779	22,455	28,982	28,287	31,846	29,777	19,297	22,320	8,537	21,728	24,757	22,962	273,727
San Joaquin 1a	1	195	273	262	258	205	263	38		60	242	266	2,063
San Joaquin 2	14	1,528	2,326	2,062	2,270	1,660	2,113	321		309	2,193	2,326	17,122
San Joaquin 3	14	1,988	2,966	2,330	2,460	2,066	2,687	409		926	2,893	2,939	21,678
South (CA)	5,292	4,885	5,266	6,081	5,236	5,104	5,115	4,840	4,195	4,761	4,814	4,977	60,566
Spaulding 1	2,402	5,236	2,473	5,471	6,576	6,312	5,999	4,317	2,542	2,581	2,228	3,875	50,012
Spaulding 2	644	2,140	2,473	2,523	2,877	1,806	627	869	253	573	363	1,905	17,053
Spaulding 3	3,359	3,774	4,822	4,176	4,477	4,397	1,145	4,428	3,945	3,181	3,393	3,955	45,052
Spring Gap	4,776	4,202	4,822	4,466	4,546	4,508	2,629	894	3,169	4,675	2,982	4,528	46,197
Stanislaus	41,692	39,575	35,260	40,657	41,885	40,644	40,301	41,027	35,698	40,856	24,282	42,158	464,035
Tiger Creek	17,170	27,646	35,260	33,434	31,862	31,102	31,367	29,321	22,560	20,027	30,112	25,219	335,080
Toadtown	876	923	1,062	1,074	1,068	916	318	91	368	325	400	771	8,192
Tule	1,490	2,940	4,633	4,489	4,608	3,749	1,761	222	719	649	1,652	4,039	30,951
Volta 1	5,484	6,203	6,711	6,515	2,524			2,943	4,612	5,142	4,676	5,732	50,542
Volta 2	695	727	793	756	526	524	809	552	574	644	585	710	7,895
West Point (CA)	6,522	9,431	10,195	9,864	6,797	9,881	9,741	8,852	7,351	6,146	10,062	10,089	104,931
Wise	10,122	3,940	5,416	1,472	8,710	6,660	9,035	9,351	9,402	6,061	7,219	9,957	87,345
Grand Total	**900,624**	**1,229,501**	**1,522,701**	**1,601,490**	**1,556,131**	**1,296,348**	**1,057,778**	**1,026,245**	**856,592**	**879,573**	**1,016,483**	**1,358,080**	**14,301,546**

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Year	1997
Plant Operator Name	PG&E

Monthly Net Generation, MWh	Month												
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
A G Wishon	281	(51)	(52)	931	4,421	4,695	4,642	2,369	7,823	9,561	4,774	5,348	44,742
Alta (CA)	13	339	390	568	600	470	660	741	766	424	243	147	5,361
Balch 1	24,696	22,603	22,457	13,683	10,591	19,858	7,750	9,980	14,969	18,736	7,103	156	172,582
Balch 2	79,212	72,013	73,755	75,670	65,374	70,444	39,282	42,758	62,050	65,193	34,463	17,258	697,472
Belden	82,911	75,112	29,362	12,267	12,005	29,487	32,402	50,699	32,647	49,630	51,632	79,283	537,437
Bucks Creek	(2)	(42)	10,243	32,630	22,165	4,660	7,241	14,942	26,354	29,853	31,658	31,782	211,484
Butt Valley	13,927	10,870	7,236	3,523	5,248	13,995	15,977	16,531	18,680	26,887	23,794	27,726	184,394
Caribou 1	54,798	49,561	36,406	24,848	27,239	47,981	52,728	53,854	48,937	16,961	14,709	38,802	466,824
Caribou 2	16,166	(49)	(37)	(40)	(55)	(64)	(48)	(24)	(22)	64,058	68,961	85,480	234,326
Centerville (CA)				1,115	2,650	2,063	2,599	2,353	376	514	854	3,246	15,770
Chili Bar	5,408	5,093	5,356	3,941	4,583	3,754	2,377	2,270	1,698	1,749	1,122	1,614	38,965
Coal Canyon				481	626	555	551	508	451	464	385	327	4,348
Coleman (CA)	7,864	7,904	8,805	8,367	8,398	7,510	6,195	4,069		5,324	6,411	7,420	78,267
Cow Creek	1,335	1,341	1,505	1,449	1,358	942	577	530	494	837	1,862	1,370	13,600
Crane Valley	563	502	572	334		292	295	146	438	519	221	210	4,092
Cresta	(22)	(14)	20,200	40,697	29,299	22,193	15,881	23,596	18,429	27,068	31,661	46,150	275,138
De Sabla	489	260	42			3,952	9,075	9,057	5,265	6,192	7,900	11,237	53,469
Deer Creek (CA)	56	(7)	(3)	2,878	3,494	2,861	2,255	2,174	2,077	2,008	1,385	1,233	20,411
Drum 1	358	(2)										1	357
Drum 2	419	(22)	(16)	16,462	36,643	35,823	36,427	36,878	21,320	(7)	13,644	36,228	233,799
Dutch Flat	1,102	(14)	(8)	(7)	(10)	(11)	(5)	(8)	(10)	(8)	(4)	1,638	2,655
Electra (CA)	35,775	50,905	55,985	54,465	55,807	52,239	36,259	38,457	34,651	37,501	10,186	22,658	484,888
Haas	81,802	93,097	74,527	59,960	34,072	78,752	42,226	50,333	76,409	79,852	37,764	10,778	719,572
Halsey	3,237	1,709	482	4,242	6,686	6,357	6,361	6,556	6,272	3,748	1,723	6,101	53,474
Hamilton Branch	30	1,078	1,832	1,131	1,210	1,684	1,756	966	587	3,510	1,306	2,145	17,235
Hat Creek 1	4,692	4,194	4,280	3,768	3,287	3,132	3,037	2,934	3,004	3,898	3,825	4,081	44,132
Hat Creek 2	5,098	4,642	3,341	5,083	4,717	4,643	4,507	4,320	4,365	5,158	5,070	5,329	56,273
Inskip	53	603	5,753	5,501	5,742	5,381	4,591	3,923	3,754	4,319	4,443	4,890	48,953
James B Black	66,014	60,965	71,714	61,461	44,193	55,852	47,414	55,835	46,332	53,680	51,546	54,790	669,796
Kerckhoff	12,222	5,580	304	2,323	22,967	17,832	65	122	(20)	(7)	10,978	(15)	72,351
Kerckhoff 2	92,960	49,411	88,148	88,293	101,113	79,832	50,497	44,640	48,969	26,567	2,055		672,485
Kern Canyon		7,587	8,391	7,942	8,315	8,118	8,341		8,054	7,354		5,915	70,017
Kilarc	1,878	2,129	2,439	2,343	2,218	1,509	1,779	1,195	1,081	1,135	1,065	1,622	20,393
Kings River	35,582	33,642	33,087	29,456	23,630	28,352	13,497	15,800	24,359	26,746	11,923	4,108	280,182
Lime Saddle	179	30	18	563	841	2,100	791	748	688	650	517	474	7,599
Merced Falls	83	1,062	2,301	1,902	1,888	1,345	2,198	1,896	1,260	925	(6)	(6)	14,848
Narrows (CA)	6,072	7,358	3,237		(30)	(8)	(1)	615	6,825	52		2	24,122
Newcastle	4,950	3,920	2,950	3,103	2,420	1,979		935	3,605	2,975	452	6,231	33,520
Oak Flat	461	447	379	467	844	802	834	837	352	352	398	407	6,580
Phoenix	292	275	1,171	1,361	1,379	1,180	859	654	908	391		17	8,487
Pit 1	31,140	29,788	26,077	27,169	27,176	25,760	26,577	25,221	25,046	27,095	26,497	27,892	325,438
Pit 3	53,257	48,102	53,052	46,043	38,190	31,151	29,376	24,908	28,061	34,496	33,977	37,547	458,160
Pit 4	70,471	64,727	69,962	60,862	50,371	39,981	38,088	34,812	35,674	43,882	43,593	45,576	597,999
Pit 5	102,122	107,618	116,748	102,215	85,279	68,139	64,260	59,217	59,893	73,121	76,217	79,987	994,816
Pit 6	52,350	50,019	45,085	39,983	31,695	2,143	25,610	25,264	22,908	26,488	29,043	31,426	382,014
Pit 7	74,924	68,524	59,026	52,933	40,977	31,762	32,178	32,236	30,013	35,385	40,676	43,105	541,739
Poe	74,396	82,482	85,951	73,115	50,489	39,055	31,785	42,939	30,653	44,889	54,805	78,066	688,625
Potter Valley	4,813	3,909	3,621	2,456	2,078	2,245	2,609	3,627	3,962	3,205	5,975	5,362	43,862
Rock Creek	42,653	75,613	78,882	62,075	40,139	34,363	29,576	39,387	23,397	39,971	46,997	73,928	586,981
Salt Springs	17,614	28,379	30,357	29,933	32,316	31,493	20,972	21,041	20,117	16,430	17,348	4,116	270,116
San Joaquin 1a	172	229	257	147	134	123	123	62	211	219	129	131	1,937
San Joaquin 2	1,744	2,058	2,323	1,323	1,019	924	979	506	1,711	2,187	1,064	1,083	16,921
San Joaquin 3	2,281	2,619	2,712	1,618	1,303	1,149	1,279	662	2,276	2,843	1,381	1,389	21,512
South (CA)	4,980	4,738	4,630	5,068	5,274	4,905	4,751	4,490	3,898	4,331	4,794	5,142	57,001
Spaulding 1	77	(16)	227	3,961	6,589	5,805	5,255	3,226	421	(8)	1,458	2,615	29,610
Spaulding 2	2,226			1,905	2,822	2,365	2,136	1,858	1,119	668	1,072	1,271	17,442
Spaulding 3	3,140	3,845	4,443	4,338	4,516	4,358	2,290	4,500	2,974	2,874	3,113	3,589	43,980
Spring Gap	1,509	1,100	3,519	4,562	4,758	4,357	274		3,247	4,818	3,014	2,519	33,677
Stanislaus	39,507	37,553	41,654	40,554	42,229	39,918	41,234	38,818	38,528	41,691	26,962	41,365	470,013
Tiger Creek	28,906	33,424	35,309	32,484	31,193	32,077	32,110	33,596	33,049	31,712	30,942	18,973	373,775
Toadtown						278	506	563	176	200	452	670	2,845
Tule	4,391	4,253	4,710	4,561	4,603	3,437	1,674	838	635	204	821	1,263	31,390
Volta 1	6,567	5,907	6,708	6,288	6,199	5,518	4,613	4,392	4,307	5,015	4,752	4,592	64,858
Volta 2	758	697	778	744	756	689	589	550	540	643	605	644	7,993
West Point (CA)	7,901	9,281	10,398	9,992	10,341	9,784	8,356	9,260	9,047	9,040	9,544	5,142	108,086
Wise	5,935	5,615	4,835	7,067	10,047	9,456	9,218	9,785	9,433	5,769	2,927	9,516	89,603
Grand Total	**1,274,788**	**1,244,495**	**1,267,816**	**1,194,557**	**1,086,421**	**1,053,776**	**878,290**	**925,947**	**925,493**	**1,041,937**	**914,181**	**1,053,092**	**12,860,793**

Year	1998
Plant Operator Name	PG&E

Monthly Net Generation, MWh	Month												
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
A G Wishon	7,695	10,373	11,658	12,176	13,050	11,593	12,536	8,596	4,884	11,616	8,530	5,045	117,752
Alta (CA)	321	475	635	417	274	55	387	531	425	389	348	156	4,413
Balch 1	299	5,851	21,353	23,396	24,458	24,353	25,086	21,656	15,932	11,418	7,837	9,531	191,170
Balch 2	10,214	49,102	43,450	76,572	78,866	77,498	80,113	70,158	52,501	41,968	28,370	35,996	644,808
Belden	9,707	10,945	23,774	16,926	18,794	70,182	58,950	67,827	68,935	38,829	64,318	73,465	522,652
Bucks Creek	21,271	27,132	38,259	39,368	35,477	41,557	40,694	33,067	22,389	26,629	30,285	29,532	385,660
Butt Valley	(6)	472	6,428	2,919	1,815	25,799	24,524	30,276	26,449	14,861	22,677	28,223	184,437
Caribou 1	1,987	130	2,291	4,527	2,101	31,182	26,833	35,878	35,545	15,015	26,188	32,102	213,779
Caribou 2	12,307	15,913	30,658	24,060	25,861	81,243	68,590	74,298	68,673	47,174	74,407	81,915	605,099
Centerville (CA)	1,565	1,750	3,236	3,575	3,854	3,657	3,959	3,926	3,280	2,567	749	2,973	35,091
Chili Bar	4,227	4,938	5,507	5,661	5,900	5,836	5,751	4,356	3,463	1,285	1,485	1,597	50,006
Coal Canyon	104		259	325	545	272			516	493	485	456	3,455
Coleman (CA)	8,628	6,870	8,817	8,546	8,758	5,577	8,416	8,190	7,673	7,801	5,788	6,348	91,412
Cow Creek	1,463	1,305	1,500	1,420	1,384	1,435	1,486	1,251	983	972	1,254	1,396	15,849
Crane Valley	240	373	437	476	540	622	617	421	210	553	327	140	4,956
Cresta	42,277	48,285	50,512	51,407	53,107	50,661	46,214	35,541	33,509	23,618	39,048	43,966	518,145
De Sabla	8,856	7,259	11,856	10,480	9,470	12,240	14,075	1,290	10,156	9,759	8,892	9,552	113,885
Deer Creek (CA)	1,430	1,405	2,232	1,045	1,582	2,015	2,066	1,990	1,982	1,682	1,438	1,326	20,193
Drum 1					(30)	9,537	10,262	13,259	7,923	8,250	6,586	14,906	70,693
Drum 2	33,179	32,204	36,622	35,604	38,683	34,618	38,754	36,800	19,705	27,952	27,289	30,732	392,142
Dutch Flat	4,024	3,915	608	10,971	13,453	10,533	5,904	5,542	3,400	4,425	5,076	9,410	77,261
Electra (CA)	29,320	43,207	53,417	54,550	53,904	54,170	56,137	54,545	48,898	39,734	37,805	41,259	566,946
Haas	(795)	39,698	44,458	66,253	80,832	99,285	105,935	84,859	64,678	49,423	29,861	40,320	704,807
Halsey	5,529	4,490	6,049	5,878	6,447	6,163	6,242	6,568	6,334	3,812	2,444	5,824	65,780
Hamilton Branch	3,006	3,173	3,501	2,992	3,714	3,646	3,560	2,340	3,414	2,875	2,273	2,485	36,979
Hat Creek 1	4,150	3,941	4,337	3,727	4,163	4,637	4,512	3,857	3,592	4,387	4,689	4,700	50,692
Hat Creek 2	5,603	5,408	6,092	5,737	5,759	6,181	6,022	5,187	5,017	5,787	5,807	5,652	68,252
Inskip	5,199	3,803	5,468	5,078	5,637	5,445	5,758	5,715	5,417	5,511	5,275	5,341	63,647
James B Black	88,041	92,258	94,589	88,020	83,713	79,386	77,093	66,843	71,129	68,446	63,825	77,160	950,503
Kerckhoff	257	803	2,991	2,320	11,014	22,929	20,316	341	(22)	1,834	12,900	(25)	75,658
Kerckhoff 2	34,667	69,101	75,138	82,121	85,952	103,291	100,071	58,714	57,708	19,962	11,813	33,891	732,429
Kern Canyon	1,742	4,538	8,227	6,560	4,825	4,283	4,624	4,960	5,083	4,962	6,442	4,902	61,148
Kilarc	2,237	2,152	2,455	2,374	2,446	2,445	2,428	2,094	1,658	1,373	1,745	1,840	25,247
Kings River	195	18,134	21,946	34,983	37,980	36,380	34,838	29,013	21,901	16,525	10,298	13,090	275,283
Lime Saddle	337	403	529	904	790	705	703	800	782	787	616	575	7,931
Merced Falls	451	1,460	2,037	2,272	2,300	2,184	2,064	2,366	2,272	1,755	(10)	(10)	19,141
Narrows (CA)	4,921	7,195	8,052	7,552	8,100	7,675	3,632	127	6,783		545	505	55,087
Newcastle	6,532	5,580	6,183	5,147	3,984	3,007	167	367	2,818	2,066	1,913	6,064	43,828
Oak Flat	412	381	397	476	652	738	862	849	438	553	346	353	6,457
Phoenix	781	1,090	1,239	1,301	1,446	1,403	1,341	1,022	759	304	270	473	11,429
Pit 1	37,149	36,759	39,272	40,995	42,413	35,700	30,041	29,487	25,664	29,878	31,637	32,107	411,102
Pit 3	48,478	47,863	52,818	51,147	52,457	50,319	39,754	33,804	34,094	39,365	42,010	48,771	540,880
Pit 4	63,843	63,659	70,746	68,301	58,590	58,259	50,011	41,970	42,491	48,629	63,525	55,140	685,164
Pit 5	107,720	106,558	117,904	113,635	117,402	113,769	86,621	72,908	73,343	83,623	94,543	107,336	1,195,362
Pit 6	52,568	53,689	58,095	55,819	46,809	51,652	38,918	30,760	31,243	32,396	37,605	44,690	534,244
Pit 7	73,484	74,000	81,574	78,742	55,286	72,396	48,291	40,147	40,840	42,731	51,608	60,401	719,500
Poe	73,797	74,909	43,342	41,835	42,277	41,096	72,186	61,852	57,541	40,213	62,445	76,928	688,421
Potter Valley	6,239	6,147	6,964	6,754	6,363	6,746	3,699	3,454	4,854	6,284	5,705	5,758	68,967
Rock Creek	61,984	72,606	79,054	80,175	82,835	80,690	86,931	37,156	55,027	35,838	67,059	73,928	813,283
Salt Springs	7,335	12,570	4,021	12,961	28,422	27,471	26,451	27,497	25,730	22,835	22,889	21,620	239,802
San Joaquin 1a	149	199	245	122	271	240	271	216	120	250	176	76	2,335
San Joaquin 2	1,107	1,607	1,839	1,974	2,829	2,140	1,996	1,383	429	2,327	1,517	615	19,763
San Joaquin 3	1,374	1,938	2,261	2,210	2,361	2,372	2,534	1,812	826	2,820	1,817	785	23,110
South (CA)	5,122	4,428	1,418	3,708	5,227	5,175	5,325	5,306	5,140	5,297	4,892	5,125	56,163
Spaulding 1	2,393	2,815	2,151	3,486	6,215	6,229	6,523	6,205	2,696	3,702	3,251	3,757	49,423
Spaulding 2	760	907	1,509	980	2,724	2,696	2,125	906	756	635	523	337	14,858
Spaulding 3	3,787	3,355	4,404	4,347	4,487	4,337	3,075	4,470	4,365	4,514	3,848	3,468	48,457
Spring Gap	3,391	3,259	4,244	4,131	4,547	4,435	4,796	4,741	2,389	4,796	4,623	3,746	49,098
Stanislaus	40,780	36,573	40,583	39,784	30,812	39,160	20,681	41,614	40,970	41,760	37,640	35,835	446,192
Tiger Creek	14,461	23,609	33,585	17,474	16,898	32,811	29,830	31,920	31,279	32,403	32,118	30,681	327,069
Toadtown	637	440	852	592	909	932	978	683	602	574	403	703	8,305
Tule	2,138	3,609	4,177	4,511	4,739	4,523	4,632	2,868	1,648	903	1,320	1,353	36,421
Volta 1	6,347	5,943	6,537	5,875	5,770	6,498	6,506	6,277	6,152	6,317	5,683	6,225	74,130
Volta 2	762	112	522	724	796	751	772	759	738	754	683	725	8,098
West Point (CA)	6,709	9,106	10,403	9,947	7,109	10,913	10,377	10,266	10,037	9,772	9,073	8,841	112,553
Wise	9,286	8,254	9,365	9,495	9,567	9,160	8,724	9,150	8,856	3,570	3,205	6,589	95,221
Grand Total	**994,173**	**1,190,426**	**1,325,082**	**1,367,840**	**1,379,715**	**1,614,888**	**1,503,570**	**1,293,031**	**1,205,022**	**1,029,538**	**1,150,032**	**1,298,706**	**15,352,023**

Year	1999												
Plant Operator Name	PG&E												
Monthly Net Generation, MWh	Month												
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
A G Wishon	3,840	8,213	10,103	7,013	6,022	6,320	3,781	7,982	8,056	7,153	484	2,402	71,369
Alta (CA)	286	382	282	188	56	238	680	498	431	462	371	185	4,059
Balch 1	2,330	3,169	(3)	(2)	7,381	16,692	11,882	13,215	13,600	10,003	185	1,289	79,741
Balch 2	6,740	13,584	23,359	34,437	49,459	54,306	50,001	51,896	57,798	47,053	6,442	13,087	408,162
Belden	34,618	48,614	(1)	8,534	13,384	27,356	51,991	57,071	25,842	37,456	61,393	52,730	418,988
Bucks Creek	25,816	23,461	40,680	26,156	23,187	7,903	23,239	29,929	1,721	25,782	28,638	12,235	268,747
Butt Valley	10,919	10,778	44	3,024	9,967	11,067	22,100	27,493	10,846	11,804	23,052	22,574	163,668
Caribou 1	15,599	16,329	143	1,117	2,252	9,420	20,919	29,401	295	15,738	38,562	22,579	172,354
Caribou 2	42,324	54,295	6,377	24,442	27,927	40,776	54,317	68,980	48,815	46,990	66,090	60,963	542,296
Centerville (CA)	2,475	1,886	1,970	2,674	3,385	3,570	2,895	2,609	2,151	1,182	2,063	2,298	29,158
Chili Bar	2,970	5,086	5,738	5,577	6,871	5,017	3,241	3,587	2,839	1,656	1,624	823	45,029
Coal Canyon	500	183	125	508	584	550	704	424	387	387	427	434	5,213
Coleman (CA)	8,555	7,669	6,459	7,253	8,475	7,553	7,810	6,676	6,066	6,368	6,996	6,933	86,813
Cow Creek	1,448	1,302	1,448	1,447	1,498	1,519	828	740	582	624	1,013	975	13,424
Crane Valley		164	272		101	104	307	535	498	413	2		2,396
Cresta	38,641	45,433	48,369	44,185	50,196	31,401	28,220	30,495	12,166	19,801	32,650	23,360	404,917
De Sabla	11,101	9,953	12,378	12,292	5,237	13,460	10,459	9,290	7,665	5,868	7,822	7,791	113,316
Deer Creek (CA)	1,909	1,275	1,352	187	1,596	2,575	2,148	2,306	2,104	2,070	1,246	1,297	20,065
Drum 1	12,481	12,809	20,396	20,738	22,358	21,556	18,661	11,921	5,201	7,892	3,279	2,934	160,226
Drum 2	26,123	29,243	32,776	31,315	32,518	29,573	30,639	35,021	17,352	21,997	20,940	21,020	328,517
Dutch Flat	8,790	6,250	13,618	12,180	12,947	11,368	11,710	15,267	6,585	5,898	6,282	5,496	116,391
Electra (CA)	42,549	42,712	48,405	47,349	53,286	53,182	55,189	39,994	35,846	53,756	36,173	31,107	539,548
Haas	234	3,012	10,162	16,252	28,583	56,165	55,919	60,417	58,575	3,303	1,458	4,556	298,636
Halsey	6,363	5,592	5,601	5,482	6,552	6,001	6,412	6,323	6,124	1,522	2,620	5,436	64,028
Hamilton Branch	2,794	3,215	3,270	3,559	3,902	3,277	2,630	1,184	1,627	3,237	1,299	2,553	32,547
Hat Creek 1	4,543	4,353	4,310	4,357	3,753	3,990	3,704	3,426	3,081	5,579	4,485	4,465	50,046
Hat Creek 2	5,967	5,482	5,971	5,038	5,298	5,432	5,196	4,963	4,783	4,710	5,685	5,883	64,408
Inskip	5,677	5,083	4,909	5,522	5,682	5,314	5,712	4,983	4,539	4,710	4,795	5,054	61,980
James B Black	75,253	75,159	89,916	74,667	80,899	68,442	64,958	56,144	64,483	46,590	45,522	60,717	802,750
Kerckhoff	(29)	(20)	203	2,122	4,919	6,990	453	720	34	6,281	5,141	2,135	28,949
Kerckhoff 2	25,451	39,200	35,222	42,436	50,277	58,905	7,925	47,140	39,695	9,176		11,483	366,910
Kern Canyon	5,854		4,115	5,358	7,078	7,878	7,925	8,243	5,893	3,532	1,178	2,227	59,281
Kilarc	2,069	2,185	2,451	2,393	2,267	1,958	1,845	1,473	1,282	1,243	1,385	1,232	21,783
Kings River	378	(45)	(64)	9,943	17,252	22,432	17,615	20,445	23,392	18,245	708	3,657	133,958
Lime Saddle	700	344	652	674	796	801	772	725	574	623	594	623	7,878
Merced Falls	750	554	1,223	1,856	2,076	1,996	2,251	1,863	1,206	1,027		77	14,879
Narrows (CA)	3,067	7,063	7,756	7,685	2,579		3,035	5,195	1,604	2,292	7,422	7,255	54,953
Newcastle	5,211	5,744	6,228	4,445	1,543	1,232	2,214		435	2,147	2,732	5,377	37,308
Oak Flat	380	349	874	689	843	809	770	831	430	521	346	377	7,219
Phoenix	417	868	1,687	1,071	1,294	1,383	802	870	893	544	147	165	10,141
Pit 1	35,493	36,295	42,021	39,122	39,748	30,787	27,804	27,568	26,321	26,652	28,591	28,491	388,893
Pit 3	46,529	47,281	52,223	48,704	41,547	41,302	33,349	32,424	33,477	37,307	36,942	37,650	488,735
Pit 4	60,840	63,067	93,502	68,170	54,810	51,363	40,092	39,566	41,702	46,405	40,763	38,760	639,040
Pit 5	102,967	100,084	117,708	113,335	112,107	90,030	71,742	69,560	72,655	80,212	81,553	83,106	1,095,059
Pit 6	43,709	42,741	53,398	50,625	46,350	35,219	28,480	25,589	26,210	27,395	24,198	29,434	433,348
Pit 7	61,394	68,245	79,489	72,681	62,561	48,063	38,355	32,933	34,015	35,271	31,675	39,575	604,257
Poe	68,480	72,965	46,572	43,618	45,490	51,428	47,259	51,628	27,346	36,311	56,257	46,873	594,227
Potter Valley	4,075	3,315	6,159	4,170	4,129	2,440	2,608	2,875	2,996	3,298	3,781	3,432	43,278
Rock Creek	64,208	63,546	59,867	67,518	73,246	47,625	43,659	48,835	22,580	30,455	51,877	47,692	621,108
Salt Springs	3,798	747	29	3,736	29,711	32,722	32,840	25,677	18,780	17,793	15,620	2,802	184,255
San Joaquin 1a	30	159	223	180	216	119	38	206	221	208			1,600
San Joaquin 2	14	638	1,055	10	335	515	579	1,624	1,703	1,525			7,998
San Joaquin 3		750	1,253		403	417	787	2,118	2,236	1,980	3		9,947
South (CA)	5,228	4,728	4,705	5,087	5,064	4,911	5,214	5,066	4,730	4,931	4,920	5,090	59,674
Spaulding 1	2,573	2,864	1,367	68	3,364	6,255	5,103	5,432	2,776	3,155	1,952	1,430	36,339
Spaulding 2	515	838	1,577	790	1,945	2,346	1,366	897	958	975	504	2,269	14,980
Spaulding 3	3,333	3,443	3,875	4,341	4,925	4,381	1,907	4,497	3,932	3,439	2,902	2,867	43,842
Spring Gap	3,925	3,804	4,629	4,576	4,687	4,445	3,546	412	2,593	4,797	1,129	2,392	40,935
Stanislaus	39,398	35,852	40,950	40,156	41,818	40,460	41,187	41,346	39,839	40,936	9,582	32,966	444,490
Tiger Creek	29,579	30,780	35,088	25,668	30,715	28,065	32,752	29,155	31,116	29,100	31,590	26,101	359,709
Toadtown	702	592	895	871	544	1,014	118	561	435	190	322	306	6,550
Tule	1,369	2,046	2,044	3,119	4,245	1,844	759	405	18	287	297	437	16,870
Volta 1	6,525	6,052	6,475	6,548	5,406	6,191	6,089	5,514	5,367	5,504	5,299	5,077	70,047
Volta 2	765	696	785	738	623	687	738	672	651	669	640	605	8,269
West Point (CA)	6,893	9,412	10,571	6,620	6,832	9,930	10,404	8,765	8,746	7,953	8,490	7,095	101,711
Wise	10,459	9,520	10,515	6,683	9,307	8,975	9,012	9,093	8,882	4,965	4,479	8,355	100,245
Grand Total	**1,047,894**	**1,111,388**	**1,135,751**	**1,101,297**	**1,194,408**	**1,160,045**	**1,087,646**	**1,142,693**	**905,781**	**897,348**	**874,617**	**868,589**	**12,527,457**

Year	2000
Plant Operator Name	PG&E

Monthly Net Generation, MWh	Month												
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
A G Wishon	3,062	9,843	11,017	7,910	8,111	4,568	6,655	3,990	3,176	9,848	5,222	240	73,642
Alta (CA)	208	293	386	132	109	184	529	511	425	326	402	200	3,705
Balch 1	3,391	2,992	6,684	15,712	24,217	24,113	19,212	12,977	5,408	726	7,766	7,105	130,303
Balch 2	9,692	20,352	51,251	40,476	74,572	76,458	69,260	58,545	34,473	10,450	41,907	40,835	528,271
Belden	15,809	6,073	23,353		18,910	35,557	63,246	55,933	53,987	45,243	42,744	46,327	407,182
Bucks Creek	15,062	19,457	21,002	26,979	33,931	13,625	22,149	14,417	17,066	20,917	26,653	8,209	239,467
Butt Valley	5,637	3,297	4,650	3,860	7,426	16,913	27,071	24,991	21,960	19,010	18,603	15,102	168,520
Caribou 1	4,570	3,190	1,275	4,316	5,520	11,081	28,352	29,553	25,345	17,590	8,687	13,357	152,836
Caribou 2	24,027	8,081	34,213	14,237	33,677	50,490	73,344	61,994	63,476	54,151	51,069	53,926	522,685
Centerville (CA)	2,556	2,678	3,757	3,701	2,550	2,369	2,590	1,926	1,562	1,181	975	1,181	27,026
Chili Bar	2,408	4,084	5,151	4,426	4,742	3,783	2,725	3,307	2,863	573	2,395	1,511	37,968
Coal Canyon	456	359	51	251	355	491	441	384	367	406	412	500	4,473
Coleman (CA)	7,361	7,854	2,839	7,980	8,275	3,367	5,011	4,918	4,790	4,901	4,859	4,938	67,093
Cow Creek	1,240	981	1,201	1,273	1,322	895	576	441	532	593	617	938	10,609
Crane Valley		458	553		238	182	395	240	183	531	255		3,035
Cresta	31,745	42,414	51,287	47,565	43,040	28,140	31,209	26,852	25,969	24,249	25,972	25,021	403,463
De Sabla	9,631	9,247	12,112	8,198	8,157	12,557	8,916	8,395	6,800	6,062	5,499	6,529	102,103
Deer Creek (CA)	1,332	1,079	1,110			2,218	2,552	2,532	1,199	1,835	1,427	2,246	17,530
Drum 1	843	9,206	18,445	18,677	20,854	19,081	13,969	12,603	5,268	5,765	3,497	1,159	129,367
Drum 2	17,151	26,372	33,228	33,887	32,863	31,496	26,983	26,654	16,042	16,910	21,456	12,640	295,682
Dutch Flat	7,747	8,193	12,814	12,211	11,418	9,733	10,141	8,307	4,875	4,710	7,840	4,644	102,633
Electra (CA)	26,335	34,873	54,160	48,363	53,554	52,031	45,662	38,107	30,554	31,194	34,551	32,402	481,786
Haas	1,306	5,405	38,546	26,542	73,231	99,654	82,993	67,450	36,157	8,659	46,918	44,425	531,286
Halsey	780		784	5,926	5,897	5,800	6,702	6,525	6,521	3,058	2,625	3,982	48,600
Hamilton Branch	2,653	3,283	2,619	2,034	3,282	2,526	2,671	972	202	718	846	1,028	22,834
Hat Creek 1	4,655	4,361	4,526	3,866	3,782	3,669	3,556	3,382	3,347	3,771	4,343	4,963	48,221
Hat Creek 2	5,840	5,662	5,945	4,740	5,262	5,056	4,921	4,753	4,658	5,441	5,552	5,804	63,634
Inskip	5,299	5,278	5,044	5,467	5,655	5,459	4,684	3,731	3,572	4,042	3,999	4,024	56,254
James B Black	64,130	86,562	94,648	82,713	78,290	60,691	51,137	50,361	50,283	56,348	48,688	47,364	771,215
Kerckhoff		140	68		10,868	12,625	11	330		2	12,228	1,350	37,622
Kerckhoff 2	12,473	29,220	68,376	71,587	84,003	77,165	46,993	33,051	26,440	24,138	2,499	6,333	482,278
Kern Canyon	3,265	1,517	3,680	7,154	8,237	8,067	7,078	7,930	4,571	3,136	1,304	2,252	58,191
Kilarc	1,940	2,257	2,408	2,342	2,431	1,945	1,428	1,159	1,114	1,148	1,084	1,130	20,386
Kings River	281	6,908	19,349	19,125	34,005	34,080	28,856	22,371	12,164	2,945	16,461	15,495	212,040
Lime Saddle	633	512	139	593	717	754	780	660	594	603	560	673	7,218
Merced Falls			1,536	1,794	2,049	2,163	2,251	1,711	1,264	1,166	6		13,940
Narrows (CA)	5,177	3,801	7,773	6,840	5,117	23	50	137	172		1,178	3,600	33,868
Newcastle	3,796	5,278	5,605	3,550	742			79	2,536	2,087	3,000	4,302	30,975
Oak Flat	373	321	358	686	796	791	823	459	410	357	336	360	6,070
Phoenix	127	824	934	1,103	1,217	1,152	953	967	849	456	300	233	9,115
Pit 1	32,892	34,205	35,219	37,120	31,714	26,045	25,958	25,833	26,337	27,506	11,604	27,890	342,323
Pit 3	47,514	46,862	51,319	45,928	37,146	33,110	29,538	31,172	31,220	34,393	35,409	36,570	460,181
Pit 4	50,946	48,885	52,840	32,278	45,755	38,713	35,055	37,204	37,699	41,886	43,459	44,534	509,254
Pit 5	104,010	99,203	117,247	102,521	82,525	71,470	64,797	66,509	67,934	74,372	77,234	76,669	1,004,491
Pit 6	40,996	43,710	42,718	42,409	33,138	26,943	23,937	24,853	25,185	26,985	25,913	29,068	385,855
Pit 7	59,726	55,939	52,768	58,123	45,449	35,790	32,317	31,003	34,076	37,809	36,199	39,700	518,899
Poe	55,740	72,637	89,376	83,877	74,723	47,647	53,684	48,054	41,652	41,390	42,016	41,320	692,116
Potter Valley	4,157	5,561	5,920	3,059	3,071	2,585	2,437	2,576	2,837	3,121	4,347	653	40,324
Rock Creek	42,722	62,739	80,578	70,855	58,245	43,021	50,919	45,829	42,883	40,586	42,736	44,814	625,927
Salt Springs	6,640	9,357	25,483	25,116	32,300	32,448	29,365	21,230	12,302	14,274	16,309	8,352	233,176
San Joaquin 1a	44	240	267	216	211	80	166	107	83	252	132		1,798
San Joaquin 2	70	1,604	2,177	7	733	516	1,298	850	678	2,156	1,078		11,167
San Joaquin 3		2,055	2,732		872	727	1,724	1,126	879	2,680	1,389		14,184
South (CA)	5,124	4,687	5,225	4,412	5,235	5,078	5,100	4,546	4,523	4,574	4,695	4,555	57,754
Spaulding 1	1,025	3,584	4,095	4,744	6,617	6,374	4,455	1,659	182	1,226	1,335	615	35,911
Spaulding 2	359	250	1,668	1,877	1,717	1,553	1,085	908	591	641	469	781	11,899
Spaulding 3	2,717	3,079	4,025	4,100	4,532	4,389	1,866	3,544	3,242	4,162	1,982	2,776	40,414
Spring Gap	1,871	3,673	4,300	4,560	4,722	4,504	2,195	348	2,214	4,727	1,854	2,304	37,272
Stanislaus	14,467	29,484	41,756	40,171	41,979	40,229	42,005	41,530	40,189	41,433	24,788	35,632	433,663
Tiger Creek	14,181	8,497	25,152	28,655	31,841	31,670	33,762	33,507	26,086	26,201	29,541	27,080	316,173
Toadtown	593	576	804	566	678	759	479	538	364	251	230	276	6,114
Tule	832	1,525	3,211	3,941	4,408	1,889	606	126		177	538	550	17,803
Volta 1	5,749	6,093	6,605	5,570	6,289	5,395	4,745	4,173	4,465	4,455	4,182	4,049	61,770
Volta 2	688	711	762	640	736	659	588	508	551	538	490	482	7,353
West Point (CA)	5,429	7,395	10,257	10,110	10,273	9,932	9,598	8,995	6,973	7,008	7,645	7,093	100,708
Wise	5,636	7,315	7,770	8,904	8,671	8,026	9,468	9,253	9,351	4,456	4,251	6,458	89,559
Grand Total	**807,119**	**942,571**	**1,287,151**	**1,165,975**	**1,293,002**	**1,200,504**	**1,174,022**	**1,049,586**	**903,670**	**842,505**	**884,560**	**868,549**	**12,419,214**

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Year	2001
Plant Operator Name	PG&E

Monthly Net Generation, MWh	Month												
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
A G Wishon	1,250	1,906	5,026	3,197	8,938	2,866	2,746	2,471	8,529	3,493	554	1,966	42,942
Alta (CA)	186	227	110	144	101	491	530	471	237	491	465	275	3,728
Balch 1	685	1,559	4,212	9,940	12,778	19,096	12,162	7,108	4,154	1,944	2,063	1,304	77,005
Balch 2	9,200	10,652	12,018	13,249	23,502	60,735	48,364	38,096	29,861	22,588	25,039	8,600	301,904
Belden	44,520	16,027	4,363	1,149	1,555	19,817	31,334	36,472	21,905	51,809	14,759	10,756	254,466
Bucks Creek	5,700	3,398	10,195	13,310	14,427	1,536	751	1,514	508	17,197	16,518	15,617	100,671
Butt Valley	19,825	8,411	1,685	1	796	11,100	16,117	15,318	5,622	17,683	7,101	4,583	108,242
Caribou 1	13,502	3,395	704	523	227	7,028	14,906	11,029	7,002	18,089	1,645	1,316	79,366
Caribou 2	56,576	29,837	6,757	3,303	7,077	30,443	41,356	41,933	29,619	67,211	27,791	19,712	361,615
Centerville (CA)	1,764	1,568	3,372	3,215	3,530	3,153	2,553	1,530	1,447	1,097	-	2,153	25,382
Chili Bar	1,266	914	1,792	2,283	2,792	549	555	429	217	1	94	943	11,835
Coal Canyon	509	475	188	314	541	484	327	33	-	23	380	374	3,648
Coleman (CA)	4,980	4,524	5,065	4,815	-	-	2,529	4,153	3,990	4,189	4,479	5,623	44,347
Cow Creek	1,026	1,047	1,262	1,219	860	360	285	212	265	343	612	935	8,426
Crane Valley	32	-	159	-	470	167	165	135	520	485	-	35	2,168
Cresta	23,920	16,486	27,769	20,102	19,859	13,271	16,140	14,938	10,065	25,004	16,973	23,122	227,649
De Sabla	1,476	2,948	10,685	9,398	6,135	10,329	8,425	8,982	5,741	5,152	7,318	10,229	86,818
Deer Creek (CA)	1,476	1,083	1,885	2,344	2,339	204	2,611	2,505	2,683	2,584	1,417	1,387	22,518
Drum 1	348	697	3,399	2,125	11,425	6,958	6,663	7,027	2,673	3,117	3,198	4,739	52,369
Drum 2	9,573	8,840	15,638	15,032	26,815	25,047	23,066	28,550	11,030	2,937	4,182	10,197	180,907
Dutch Flat	3,360	2,876	4,690	4,443	7,764	6,328	6,013	6,688	2,281	1,614	2,558	5,063	53,678
Electra (CA)	15,255	10,295	25,027	32,723	26,907	28,741	32,047	29,818	26,439	23,842	17,836	28,360	297,290
Haas	4,692	6,687	621	2,677	6,299	75,333	59,167	43,018	31,731	22,007	28,624	2,318	283,174
Halsey	1,810	3,124	5,891	5,669	6,454	6,094	6,117	5,777	4,214	1,492	547	2,785	49,974
Hamilton Branch	733	725	1,447	455	355	284	875	961	451	431	282	830	7,829
Hat Creek 1	4,267	3,850	4,120	3,496	3,106	2,917	3,006	2,917	2,863	3,244	3,834	4,065	41,685
Hat Creek 2	5,494	4,922	5,318	4,702	4,352	4,089	4,187	4,123	4,030	4,368	4,894	5,176	55,655
Inskip	4,064	3,925	4,840	4,636	5,122	3,389	2,824	2,531	2,387	2,434	3,278	4,650	44,080
James B Black	50,303	52,522	61,490	55,281	52,815	46,071	48,952	49,772	41,318	40,650	56,079	56,416	611,669
Kerckhoff	-	-	-	-	3,615	-	4	7	-	-	4,872	2,271	10,769
Kerckhoff 2	9,951	8,192	30,976	46,513	68,356	44,470	21,454	35,575	27,776	12,244	583	10,513	316,603
Kern Canyon	1,636	2,068	3,504	5,541	7,419	7,281	8,084	6,540	3,886	2,376	1,539	2,802	52,676
Kilarc	1,016	938	1,697	2,090	2,038	1,079	914	801	673	679	916	1,012	13,853
Kings River	2,237	3,695	3,625	6,122	10,532	25,890	19,661	13,527	10,065	7,015	7,518	2,411	112,298
Lime Saddle	683	612	348	715	803	691	535	464	382	400	544	537	6,714
Merced Falls	-	-	300	1,468	2,202	2,140	2,200	1,828	863	1,033	-	-	12,034
Narrows (CA)	31	4,857	7,365	-	-	-	57	4	4,724	2,547	400	3,874	23,859
Newcastle	1,516	3,565	5,324	4,082	2,156	1,183	69	-	-	-	-	3,160	21,055
Oak Flat	357	284	321	383	753	784	799	818	401	369	329	14	5,612
Phoenix	467	371	420	1,353	1,318	892	1,029	1,128	1,066	424	242	1,274	9,984
Pit 1	27,351	24,342	27,571	27,550	25,461	22,373	22,827	23,022	22,837	23,450	24,644	27,284	298,712
Pit 3	34,538	32,135	35,304	33,203	31,304	26,242	26,607	27,489	27,753	28,319	32,492	38,021	373,407
Pit 4	42,481	40,233	42,214	39,325	38,675	32,237	32,770	33,858	34,323	34,484	40,357	48,525	459,482
Pit 5	73,809	70,542	75,466	72,451	67,529	59,109	58,293	58,942	58,367	50,834	70,623	85,495	801,460
Pit 6	28,057	26,991	32,649	29,540	27,343	22,875	23,871	24,329	21,855	23,458	28,939	36,853	326,760
Pit 7	38,870	40,467	48,180	41,205	36,554	30,832	31,238	31,643	23,926	30,781	35,485	56,824	446,005
Poe	39,569	28,563	50,348	35,404	33,981	20,959	24,905	22,506	15,505	39,014	27,753	44,827	383,334
Potter Valley	751	842	2,330	4,075	2,887	2,290	1,657	1,683	1,727	2,151	3,855	5,981	30,229
Rock Creek	43,854	25,477	37,526	25,555	22,145	19,343	25,629	23,375	17,650	41,487	22,896	32,876	337,813
Salt Springs	465	519	5,980	7,529	11,497	17,625	17,816	16,778	15,846	12,777	3,594	8,961	119,387
San Joaquin 1a	11	6	95	-	211	71	72	61	165	224	-	21	937
San Joaquin 2	144	39	658	4	1,552	505	576	524	1,871	1,835	-	174	7,882
San Joaquin 3	157	-	692	-	1,991	755	752	684	2,467	2,405	-	168	10,071
South (CA)	4,556	4,277	5,138	5,004	5,128	4,088	3,522	3,196	3,043	3,248	3,911	5,060	50,171
Spaulding 1	656	267	947	1,333	5,019	4,243	2,471	2,163	656	209	304	682	18,950
Spaulding 2	511	384	533	760	542	109	1,208	1,086	995	1,048	584	439	8,199
Spaulding 3	41	-	844	1,826	2,467	2,500	905	3,766	2,411	1,050	589	999	17,398
Spring Gap	1,947	2,692	4,506	4,544	4,842	3,650	891	205	2,095	2,184	1,875	4,549	33,980
Stanislaus	11,479	11,482	15,152	32,782	41,918	40,128	42,924	33,928	21,580	15,791	8,659	32,624	308,447
Tiger Creek	10,692	5,301	14,170	19,672	14,744	25,694	30,347	29,106	24,838	21,444	15,141	21,302	232,451
Toadtown	255	156	547	501	448	654	490	354	221	155	312	646	4,739
Tule	624	944	2,612	3,394	4,218	1,149	558	32	-	15	649	1,351	15,546
Volta 1	3,843	3,494	4,240	4,379	4,095	3,541	3,138	1,588	1,650	2,577	2,732	4,219	39,496
Volta 2	470	426	544	543	500	425	344	299	279	268	272	314	4,684
West Point (CA)	2,685	1,759	5,388	6,522	5,575	6,847	7,811	7,067	6,204	5,234	3,740	6,324	65,156
Wise	3,261	5,599	9,307	8,648	9,225	8,435	5,246	7,948	5,501	1,935	939	5,292	71,336
Grand Total	**676,763**	**554,439**	**706,549**	**693,761**	**756,384**	**827,969**	**816,447**	**784,835**	**625,383**	**718,983**	**599,808**	**731,208**	**8,492,529**

Year	2002
Plant Operator Name	PG&E

Monthly Net Generation, MWh	Month												
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
A G Wishon	8,877	829	4,175	1,979	4,815	2,843	1,688	2,566	9,368	9,387	1,026	6,810	54,363
Alta (CA)	180	256	341	128	88	459	809	523	251	558	470	344	4,407
Balch 1	9,565	12,459	3	5,591	7,630	5,185	13,756	16,202	4,486	1,522	4,551	4,640	85,590
Balch 2	25,063	35,334	30,676	29,937	43,518	37,055	52,393	58,575	34,148	21,593	30,430	31,695	430,417
Belden	2,887	1,958	2,827	1,185	2,967	4,084	18,246	33,750	49,561	41,904	23,697	22,512	205,578
Bucks Creek	22,346	7,532	12,130	21,414	16,209	2,024	10,614	14,531	26,951	26,120	25,753	25,269	210,893
Butt Valley	1	180	24	4	-	1,886	12,539	16,461	23,173	18,537	9,972	6,806	89,583
Caribou 1	100	169	1,055	275	340	1,049	16,257	28,547	27,517	14,655	4,611	4,007	98,582
Caribou 2	6,618	4,521	5,470	3,410	10,572	12,885	19,429	26,904	53,487	54,128	38,130	34,582	270,136
Centerville (CA)	2,270	2,589	3,046	3,757	3,556	2,641	2,431	2,155	1,650	762	105	42	25,004
Chili Bar	1,874	1,409	1,674	2,590	2,954	649	1,490	1,743	2,048	1,680	1,610	1,746	21,467
Coal Canyon	425	422	57	-	-	-	-	-	-	-	-	-	904
Coleman (CA)	8,048	7,106	8,602	8,364	5,188	6,219	4,727	3,902	3,828	3,849	4,303	6,385	70,521
Cow Creek	1,228	1,113	1,278	1,235	1,282	650	261	196	177	276	516	858	9,070
Crane Valley	454	-	175	-	286	177	113	175	585	508	-	295	2,768
Cresta	27,851	18,572	24,205	28,943	18,053	5,010	10,542	15,102	21,684	19,626	17,306	32,684	239,578
De Sabla	11,983	11,439	12,580	11,922	7,012	10,123	6,366	6,069	4,876	3,170	5,104	6,062	96,706
Deer Creek (CA)	1,347	1,355	1,744	654	1,878	2,745	2,335	2,553	2,230	2,220	1,329	1,262	21,652
Drum 1	16,982	1,441	7,921	21,731	21,869	15,710	10,317	6,551	2,025	3,067	1,154	2,142	110,910
Drum 2	30,044	21,227	32,265	29,709	29,495	26,405	28,204	29,302	13,246	20,764	20,264	23,306	304,231
Dutch Flat	10,204	591	-	-	2,196	7,845	1,941	869	59	9,759	9,415	9,950	52,829
Electra (CA)	41,221	23,492	45,917	41,680	28,677	40,530	28,021	26,459	27,151	30,312	28,872	35,207	397,539
Haas	27,133	39,201	16,638	14,051	26,877	32,672	62,833	72,170	35,795	19,712	23,106	30,410	400,598
Halsey	8,191	5,742	6,058	6,275	6,381	5,890	6,366	6,308	5,086	2,517	2,546	4,045	65,405
Hamilton Branch	2,247	1,659	1,736	590	438	395	277	1,492	1,279	485	1,215	1,693	13,506
Hat Creek 1	3,985	3,459	3,654	2,901	3,009	2,807	2,770	2,709	2,612	2,843	2,458	3,696	36,903
Hat Creek 2	5,163	4,457	4,837	4,075	4,186	3,938	3,917	3,822	3,559	3,955	4,545	3,097	49,551
Inskip	4,895	3,614	5,523	5,376	5,258	4,492	3,143	2,665	2,449	2,533	3,033	3,679	46,660
James B Black	68,123	54,413	68,154	66,233	53,682	35,342	46,682	51,416	39,541	41,121	41,338	63,794	629,839
Kerckhoff	-	56	-	15	3,617	6,396	7	-	-	-	7,782	1,763	19,636
Kerckhoff 2	28,223	25,856	29,570	48,135	51,488	49,496	31,292	37,527	30,302	17,296	1,175	18,037	368,397
Kern Canyon	937	2,301	998	5,089	6,640	7,522	7,725	6,581	2,852	1,844	3,211	4,171	49,871
Kilarc	1,758	1,463	2,380	2,333	2,464	1,727	1,098	870	792	806	838	1,159	17,688
Kings River	10,066	14,500	9,060	11,130	16,132	13,164	21,717	24,375	11,756	6,389	10,969	11,493	160,751
Lime Saddle	556	584	237	727	780	742	685	553	478	525	611	509	6,987
Merced Falls	-	-	219	1,613	1,641	1,965	2,083	1,583	1,042	620	-	-	10,766
Narrows (CA)	10	-	811	-	-	-	-	-	6,655	2,171	56	1,575	11,278
Newcastle	6,116	5,508	5,363	4,495	2,619	581	-	1,405	2,584	903	2,697	4,226	36,497
Oak Flat	-	-	243	602	825	760	481	849	311	354	257	296	4,978
Phoenix	1,298	1,083	1,389	1,325	1,249	833	1,062	1,148	1,056	577	203	457	11,680
Pit 1	29,040	23,833	26,647	29,082	25,711	20,907	20,702	21,201	20,617	22,290	22,694	25,895	288,619
Pit 3	43,743	34,059	41,517	34,784	31,210	25,517	24,921	23,815	25,904	27,685	31,251	35,033	379,439
Pit 4	55,442	43,695	53,233	45,083	40,312	32,307	31,080	26,645	32,641	32,124	36,414	43,271	472,247
Pit 5	95,714	76,154	93,042	80,283	72,308	57,073	54,449	52,748	56,800	59,858	56,460	77,247	832,136
Pit 6	40,311	31,931	39,661	33,671	29,353	21,605	22,654	22,822	21,428	21,975	23,943	34,493	343,847
Pit 7	61,628	43,538	50,993	50,257	41,823	29,311	30,266	30,406	26,550	29,294	31,709	48,325	474,100
Poe	49,889	35,087	51,570	55,928	38,112	16,010	21,160	28,622	36,558	38,037	34,280	46,747	452,000
Potter Valley	5,690	5,638	5,959	2,382	1,916	1,641	1,558	1,642	1,854	1,802	1,948	2,517	34,547
Rock Creek	33,055	26,770	31,025	32,501	17,868	7,517	17,488	27,015	35,578	30,960	23,453	48,874	332,104
Salt Springs	12,937	5,130	22,760	17,752	23,725	29,509	16,157	15,451	19,275	21,952	18,470	22,338	225,456
San Joaquin 1a	243	-	87	6	120	71	45	72	258	261	-	165	1,328
San Joaquin 2	1,729	25	37	-	-	-	-	-	-	1,964	52	1,267	5,074
San Joaquin 3	2,126	-	880	36	1,101	682	488	853	2,771	2,623	-	1,616	13,176
South (CA)	5,145	4,620	3,796	4,912	5,205	4,657	3,779	3,252	3,018	3,087	3,463	3,008	47,942
Spaulding 1	1,760	608	1,813	4,034	5,409	5,623	4,931	3,473	1,336	2,504	1,544	1,715	34,750
Spaulding 2	353	350	439	546	1,260	1,423	1,004	1,019	902	896	485	352	9,029
Spaulding 3	3,036	2,528	2,765	4,156	3,732	2,961	-	-	-	-	-	2,106	21,284
Spring Gap	4,255	1,385	4,122	4,402	4,723	4,662	1,463	553	1,959	2,160	2,686	3,605	35,975
Stanislaus	42,196	19,154	41,739	40,512	41,820	38,661	41,641	41,896	40,303	40,123	14,732	40,755	443,532
Tiger Creek	30,579	14,168	31,109	27,488	17,637	30,666	26,876	27,512	27,130	30,460	28,895	30,023	322,543
Toadtown	913	859	950	632	545	638	322	351	211	-	140	271	5,832
Tule	2,112	1,550	2,695	4,253	4,222	2,297	772	344	-	-	976	1,893	21,114
Volta 1	5,833	4,742	5,843	3,852	5,369	3,817	3,184	2,741	2,611	2,609	2,470	3,312	46,383
Volta 2	556	575	698	438	297	443	371	323	308	308	296	390	5,003
West Point (CA)	9,495	5,517	10,169	9,082	5,107	8,339	6,812	6,826	8,625	7,279	6,717	8,358	92,326
Wise	9,960	9,378	9,917	9,524	9,530	8,583	9,057	9,209	8,590	3,277	4,601	6,876	98,502
Grand Total	**946,009**	**709,184**	**886,501**	**885,069**	**824,286**	**709,816**	**775,797**	**857,399**	**831,877**	**772,576**	**682,337**	**901,156**	**9,782,007**

Year	2003
Plant Operator Name	PG&E

Monthly Net Generation, MWh	Month												
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
A G Wishon	1,341	3,679	4,613	3,568	8,778	7,232	70	3,305	9,591	10,035	1,736	1,039	54,987
Alta (CA)	273	42	87	236	242	335	504	524	476	667	303	186	3,875
Balch 1	1,452	13,281	5,359	3,043	8,760	9,041	11,405	10,272	10,573	5,551	5,556	12,044	96,337
Balch 2	12,945	31,550	33,691	25,772	41,723	45,131	46,097	41,482	38,671	23,832	23,157	43,490	407,541
Belden	14,831	36,867	8,685	1,830	4,765	32,551	39,070	45,313	46,733	35,472	43,614	43,853	353,584
Bucks Creek	29,347	17,046	19,433	20,072	29,294	34,109	14,911	16,904	24,618	26,740	22,361	30,196	285,031
Butt Valley	5,770	14,592	904	-	764	15,112	19,612	22,280	21,194	16,095	19,650	17,347	153,320
Caribou 1	3,583	21,026	1,234	784	1,880	756	18,402	25,538	14,796	12,872	16,970	23,767	141,608
Caribou 2	23,247	37,931	12,940	2,405	15,959	57,195	50,425	58,554	63,755	49,035	56,069	53,287	480,802
Centerville (CA)	2,253	3,201	3,445	3,224	2,509	2,502	3,255	3,076	2,309	962	-	1,758	28,494
Chili Bar	2,989	2,371	2,429	3,849	5,349	3,154	2,825	1,801	1,265	654	1,393	7,020	35,099
Coal Canyon	-	-	-	-	-	-	-	-	-	-	-	-	-
Coleman (CA)	8,737	7,840	8,543	8,338	8,567	8,388	7,330	2,853	4,469	4,433	4,941	7,720	82,159
Cow Creek	1,260	1,149	1,256	1,242	1,292	1,128	655	576	485	467	755	1,062	11,327
Cresta	47,006	37,045	32,164	37,236	51,127	34,951	20,216	21,433	20,831	17,827	21,340	36,256	377,432
De Sabla	12,198	11,112	12,491	8,332	2,753	9,118	7,511	8,435	6,419	3,544	5,272	8,699	95,884
Deer Creek (CA)	1,579	2,143	2,228	-	2,300	2,683	2,289	2,157	1,955	1,836	1,500	1,277	21,947
Drum 1	14,992	16,309	11,348	10,418	19,439	18,781	12,703	9,663	4,111	22,609	11,424	7,759	159,556
Drum 2	33,311	30,995	30,904	29,788	34,487	30,168	27,208	24,117	10,589	-	21,353	28,151	301,071
Dutch Flat	11,846	3,165	12,514	11,379	13,518	9,255	6,604	8,741	3,604	6,051	5,710	9,825	102,212
Electra (CA)	47,235	40,605	35,065	30,162	50,884	48,866	30,220	29,930	32,743	32,639	28,253	37,456	444,058
Haas	3,887	34,712	21,203	9,937	13,231	33,529	51,705	48,833	45,595	26,606	25,527	47,419	362,184
Halsey	4,708	4,381	4,909	5,463	5,952	6,129	6,414	6,510	6,325	3,573	2,148	4,764	61,276
Hamilton Branch	3,477	1,430	1,471	2,477	3,489	1,243	275	2,842	2,591	1,276	804	2,425	23,800
Hat Creek 1	3,811	3,287	3,552	3,276	3,117	3,144	2,787	2,686	2,474	2,660	3,291	3,581	37,666
Hat Creek 2	5,043	4,439	4,875	4,583	4,550	4,396	4,083	3,892	3,413	3,864	4,493	4,787	52,418
Inskip	5,503	4,150	4,493	5,365	5,607	5,433	5,337	4,027	3,377	3,319	3,575	4,998	55,184
James B Black	86,756	56,584	72,741	74,397	79,486	47,135	53,942	50,054	42,952	40,587	38,195	75,092	717,921
Kerckhoff	-	6	106	71	4,199	11,499	8	-	-	-	1,910	1,051	18,850
Kerckhoff 2	23,906	26,933	26,830	43,761	71,256	76,119	47,843	38,088	25,717	25,327	4,430	13,766	423,976
Kern Canyon	3,145	-	3,373	4,431	6,310	7,421	7,055	7,646	6,902	5,412	1,432	2,371	55,498
Kilarc	1,922	2,169	2,379	2,284	2,403	2,223	1,645	1,229	1,046	976	904	1,455	20,635
Kings River	2,779	14,162	12,830	9,342	16,600	17,256	18,508	16,212	15,210	8,235	7,497	17,467	156,098
Lime Saddle	555	558	312	582	596	517	696	691	589	540	528	502	6,666
Merced Falls	-	-	482	1,276	1,925	2,061	2,140	1,691	1,003	736	-	-	11,314
Narrows (CA)	14	2	635	388	8,207	2,995	-	53	8,004	6,241	-	5	26,544
Newcastle	5,426	4,948	4,821	4,245	2,880	1,092	-	285	2,937	2,275	2,242	4,433	35,584
Oak Flat	337	311	301	293	824	812	851	741	349	323	272	274	5,688
Phoenix	1,170	1,151	1,239	1,310	1,395	1,175	1,107	970	1,067	689	544	710	12,527
Pit 1	30,505	25,390	31,613	30,312	29,923	18,518	17,094	7,984	18,551	19,628	21,202	24,209	274,929
Pit 3	38,570	35,485	41,817	41,376	49,034	29,285	26,150	20,247	28,342	28,313	29,104	37,613	405,336
Pit 4	55,925	45,430	46,813	57,718	54,942	37,611	33,166	25,608	35,924	35,668	36,903	47,968	513,676
Pit 5	97,872	78,612	94,266	95,116	89,173	66,129	58,505	46,897	62,068	63,396	63,837	83,502	899,373
Pit 6	42,792	35,650	42,088	44,259	49,546	26,220	24,524	20,725	23,590	22,597	21,809	35,768	389,568
Pit 7	65,850	41,500	45,794	63,207	70,449	37,116	32,851	27,437	31,154	30,412	30,004	53,814	529,588
Poe	84,987	68,947	60,673	68,318	88,134	62,559	38,700	40,432	39,378	32,602	43,666	67,897	696,293
Potter Valley	2,592	4,715	5,476	5,001	5,760	3,491	3,040	3,304	4,633	3,337	3,058	5,420	49,827
Rock Creek	70,078	58,804	43,279	52,639	76,136	46,921	34,032	37,300	34,632	28,964	34,609	63,616	581,010
Salt Springs	8,515	11,321	20,140	10,003	26,345	32,176	18,118	22,048	22,243	5,872	15,100	23,827	215,708
San Joaquin 2	10	537	610	97	1,688	1,414	-	717	2,053	2,152	280	41	9,599
San Joaquin 3	-	697	779	169	2,093	1,839	-	925	1,440	1,914	444	-	10,300
South (CA)	5,182	4,711	4,685	5,085	5,198	5,013	5,040	4,557	4,026	3,977	4,188	5,086	56,748
Spaulding 1	3,261	2,764	2,109	3,687	4,967	5,378	5,140	3,874	1,600	-	1,291	2,756	36,827
Spaulding 2	791	1,417	642	103	2,332	1,776	1,206	1,069	413	-	221	459	10,429
Spaulding 3	4,102	4,111	2,897	3,633	4,745	2,189	4,274	3,965	3,470	3,440	2,360	2,464	41,650
Spring Gap	4,042	4,216	4,547	4,475	4,713	4,584	2,090	1,145	3,735	4,179	2,843	2,041	42,610
Stanislaus	38,556	26,487	32,807	39,779	41,599	41,072	41,604	40,676	35,897	-	-	-	338,477
Tiger Creek	33,646	29,341	25,129	9,781	11,190	30,293	27,580	28,643	26,539	32,123	27,262	28,739	310,266
Toadtown	883	806	928	466	283	1,020	603	524	332	-	175	504	6,524
Tule	2,500	1,941	3,432	3,769	4,578	3,453	1,427	752	69	500	672	1,007	24,100
Volta 1	6,010	5,382	5,632	6,458	5,002	5,730	4,400	3,633	3,361	3,169	3,056	3,843	55,676
West Point (CA)	10,386	8,514	8,795	4,778	5,182	9,521	7,464	7,170	7,889	7,853	6,984	9,327	93,863
Wise	7,661	7,066	7,706	8,497	8,898	8,741	9,011	9,256	9,066	5,303	3,549	7,611	92,365
Grand Total	**1,043,350**	**995,016**	**938,542**	**933,885**	**1,178,327**	**1,076,684**	**921,727**	**882,292**	**889,143**	**739,359**	**741,766**	**1,064,804**	**11,404,895**

Year	2004
Plant Operator Name	PG&E

Monthly Net Generation, MWh	Month											
Plant Name	1	2	3	4	5	6	7	8	9	10	11	12	Grand Total
A G Wishon	7,507	1,866	11,374	1,602	660	489	105	3,568	9,184	10,183	5,504	1,283	53,325
Alta (CA)	132	225	352	215	271	511	659	579	475	490	227	196	4,332
Balch 1	10,783	914	12,390	13,797	9,505	8,581	10,549	10,236	3,679	858	3,575	5,405	90,272
Balch 2	43,835	31,202	21,718	31,611	39,693	45,049	48,228	50,080	20,531	8,929	8,645	18,890	368,411
Belden	66,061	16,867	4,514	5,791	1,581	13,349	40,738	52,660	36,434	29,248	36,100	39,483	342,826
Bucks Creek	14,043	11,406	22,055	26,442	19,765	20,851	15,709	23,810	9,529	15,880	27,484	30,482	237,456
Butt Valley	28,078	608	-	-	-	9,790	20,813	26,576	17,861	11,439	16,597	17,412	149,174
Caribou 1	34,068	8,771	295	1,088	1,816	7,622	29,375	29,719	9,092	3,741	8,831	11,440	145,858
Caribou 2	68,750	21,952	10,435	15,056	4,689	19,776	41,954	59,503	49,280	48,172	53,597	56,109	449,273
Centerville (CA)	2,347	598	2,865	3,352	3,981	3,807	2,972	2,615	1,844	1,302	1,671	2,075	29,429
Chili Bar	2,658	2,641	4,088	3,207	2,736	1,926	1,961	2,383	2,213	1,147	320	806	26,086
Coal Canyon	-	-	-	-	-	-	-	-	-	-	-	-	-
Coleman (CA)	8,041	7,892	8,866	8,516	610	3,837	5,420	175	3,469	4,420	4,704	5,554	61,504
Cow Creek	1,204	1,187	1,284	1,245	1,290	941	497	407	341	595	815	967	10,773
Cresta	40,131	32,443	46,432	35,251	23,876	14,828	20,130	24,281	16,303	15,317	20,413	26,356	315,761
De Sabla	10,247	8,119	1,740	11,360	13,860	11,591	7,631	7,263	5,521	4,991	5,806	7,956	96,085
Deer Creek (CA)	368	1,041	1,304	-	2,360	2,557	2,634	2,769	2,922	2,340	1,670	1,616	21,581
Drum 1	14,185	1,103	16,422	15,828	13,162	5,085	6,377	6,059	5,895	1,293	1,849	-	87,258
Drum 2	27,548	26,081	34,408	34,336	35,487	28,479	26,984	27,664	9,267	13,465	20,977	23,602	308,298
Dutch Flat	11,205	1,370	8,613	9,928	8,147	8,500	9,126	7,444	5,378	6,537	10,307	10,967	97,522
Electra (CA)	41,110	33,294	50,037	29,693	11,344	41,077	28,878	30,304	27,321	12,639	31,217	36,523	373,437
Haas	47,179	23,202	11,105	25,534	31,587	47,652	55,545	58,301	21,256	3,623	7,087	19,266	351,337
Halsey	5,639	5,076	6,094	5,920	6,057	5,746	6,145	6,222	4,177	1,880	3,509	5,763	62,228
Hamilton Branch	2,065	1,822	2,672	2,122	2,246	932	417	352	2,168	2,597	1,019	1,633	20,045
Hat Creek 1	3,458	3,422	3,665	2,764	2,964	2,992	2,754	2,470	2,194	2,893	3,272	3,314	36,162
Hat Creek 2	4,695	4,614	5,122	4,103	4,286	4,238	3,968	3,713	3,177	4,117	4,442	4,498	50,973
Inskip	4,562	4,949	5,513	5,266	5,385	5,117	4,063	3,072	2,798	3,175	3,425	3,788	51,113
James B Black	55,754	67,946	92,962	76,858	55,927	50,322	52,984	56,246	51,485	44,449	38,383	47,500	690,816
Kerckhoff	-	-	1	22	7	4,608	7	-	-	6,949	4,070	169	15,833
Kerckhoff 2	24,488	21,505	48,529	48,769	47,247	37,102	36,348	26,921	24,149	6,605	17,552	23,758	362,973
Kern Canyon	1,840	2,251	5,853	7,724	7,470	7,498	7,925	7,320	4,567	817	1,032	1,448	55,745
Kilarc	1,212	1,381	2,306	2,272	2,323	1,943	1,308	1,010	851	1,004	859	1,122	17,591
Kings River	3,383	9,948	10,400	13,417	15,231	16,886	19,003	19,091	6,748	2,254	3,181	7,412	126,954
Lime Saddle	530	382	486	592	696	678	657	560	505	84	366	391	5,927
Merced Falls	-	-	421	1,622	2,068	1,991	2,143	1,694	1,044	503	-	-	11,486
Narrows (CA)	702	2,329	633	-	-	-	1	-	4,679	-	1,963	5,139	15,446
Newcastle	5,882	4,881	5,518	3,843	1,828	356	-	362	1	-	3,751	6,193	32,615
Oak Flat	315	311	379	548	823	812	832	835	441	348	314	314	6,272
Phoenix	668	652	1,156	1,125	1,170	1,026	1,054	1,154	1,095	552	247	599	10,498
Pit 1	24,252	23,593	30,093	27,578	20,119	18,457	15,750	15,854	17,546	19,176	21,219	23,309	256,946
Pit 3	41,457	41,492	41,808	37,454	31,998	28,589	26,333	24,848	23,793	29,634	30,114	34,451	391,971
Pit 4	52,946	54,026	66,521	48,442	40,033	35,411	32,234	30,376	28,925	31,556	37,005	42,329	499,804
Pit 5	91,587	87,228	108,579	79,529	73,038	64,804	59,458	55,981	54,651	66,231	68,731	77,681	887,498
Pit 6	33,770	41,112	48,824	37,892	28,616	23,916	22,737	22,547	20,535	24,239	22,607	27,644	354,439
Pit 7	45,209	58,907	72,902	54,015	45,398	36,546	34,092	30,267	28,437	29,689	29,252	40,020	504,734
Poe	75,625	61,894	84,705	66,017	47,305	29,681	37,176	43,839	29,028	34,225	40,311	51,723	601,529
Potter Valley	5,846	4,658	5,404	3,210	2,974	3,022	2,566	3,057	2,996	3,360	2,548	4,274	43,915
Rock Creek	66,126	51,168	69,882	44,344	25,276	16,523	32,890	39,895	28,079	28,092	36,255	39,756	478,286
Salt Springs	4,507	5,700	11,222	19,341	15,195	22,541	9,383	21,706	20,574	3,024	5,757	16,770	155,720
San Joaquin 2	1,357	42	1,732	34	-	-	-	758	1,996	1,955	940	-	8,814
San Joaquin 3	1,698	-	2,402	164	-	-	-	926	2,595	2,488	1,221	-	11,494
South (CA)	5,015	4,781	4,352	4,894	5,205	5,007	4,536	3,766	3,493	4,006	4,066	4,435	53,556
Spaulding 1	1,802	453	1,672	4,209	5,966	4,387	4,206	3,558	1,385	987	1,942	1,571	32,138
Spaulding 2	402	247	938	-	1,324	1,437	1,375	1,366	1,502	603	-	-	9,194
Spaulding 3	3,411	3,086	4,164	440	-	-	4,197	4,359	3,450	3,024	2,183	917	29,231
Spring Gap	2,332	3,408	4,718	4,621	4,802	4,384	1,104	127	1,256	3,464	3,528	3,769	37,513
Stanislaus	25,074	38,137	41,428	40,017	41,696	20,749	21,526	41,683	39,543	41,192	16,966	39,013	407,024
Tiger Creek	31,789	20,816	30,070	19,982	10,663	31,321	29,021	30,795	28,158	10,130	27,011	31,367	301,123
Toadtown	-	565	200	773	1,086	838	399	444	306	70	134	377	5,192
Tule	1,612	1,688	3,750	3,509	3,076	1,312	576	156	-	277	545	582	17,083
Volta 1	4,399	5,219	6,475	5,379	5,684	4,277	3,545	3,012	2,948	3,182	3,117	3,053	50,290
West Point (CA)	10,132	7,823	9,592	6,959	3,248	9,087	7,370	7,877	6,982	2,994	7,412	8,948	88,424
Wise	8,896	8,644	9,389	9,042	8,667	8,111	8,661	8,768	5,794	2,596	5,603	9,412	93,583
Grand Total	**1,133,917**	**888,938**	**1,122,829**	**968,664**	**803,517**	**808,945**	**875,029**	**953,383**	**721,846**	**621,030**	**723,248**	**890,830**	**10,512,176**

Year	2005
Plant Operator Name	PG&E

Sum of Net Generation MWh	Month				
Plant Name	1	2	3	4	Grand Total
A G Wishon	10350	11729	12872	12051	47002
Alta (CA)	337	298	303	213	1151
Balch 1	10383	14937	15384	730	41434
Balch 2	41161	37939	39067	74600	192767
Belden	40898	13136	4518	3900	62452
Bucks Creek	20208	7883	16752	17785	62628
Butt Valley	19722	5963	35	25	25745
Caribou 1	16485	3736	2016	261	22498
Caribou 2	51581	22837	6671	6706	87795
Centerville (CA)	2391	1517	2923	3296	10127
Chili Bar	3317	3397	4514	5339	16567
Coal Canyon	0	0	0	0	0
Coleman (CA)	6608	5898	7393	7700	27599
Cow Creek	1182	802	1090	1180	4254
Cresta	30095	24705	41676	41847	138323
De Sabla	6626	9453	10773	8553	35405
Deer Creek (CA)	0	637	1840	514	2991
Drum 1	3415	9129	9858	14241	36643
Drum 2	26668	29670	30915	33427	120680
Dutch Flat	11720	4540	8978	11385	36623
Electra (CA)	50630	47672	55594	44610	198506
Haas	33269	39123	24712	69200	166304
Halsey	5165	5585	4002	5107	19859
Hamilton Branch	1180	2379	2987	624	7170
Hat Creek 1	3266	2798	3102	2692	11858
Hat Creek 2	4447	3837	4218	3791	16293
Inskip	3049	2858	4444	4867	15218
James B Black	52946	53373	80473	69087	255879
Kerckhoff	77	0	430	225	732
Kerckhoff 2	32823	47918	79437	83382	243560
Kern Canyon	4714	0	4578	6817	16109
Kilarc	1057	1447	2151	2223	6878
Kings River	5937	17410	18778	32246	74371
Lime Saddle	332	373	376	203	1284
Merced Falls	0	0	244	1936	2180
Narrows (CA)	506	63	709	37	1315
Newcastle	5613	5091	3537	3938	18179
Oak Flat	0	182	196	0	378
Phoenix	1011	1041	1202	1066	4320
Pit 1	23757	21639	27287	28306	100989
Pit 3	32561	31956	39791	38335	142643
Pit 4	40537	39671	42276	41649	164133
Pit 5	74287	72872	88850	86226	322235
Pit 6	28024	27205	41598	37938	134765
Pit 7	40337	42283	60795	54735	198150
Poe	61144	51937	74236	75718	263035
Potter Valley	5511	5086	4784	4894	20275
Rock Creek	45813	37286	61755	58496	203350
Salt Springs	11896	12848	23701	19378	67823
San Joaquin 2	1410	1944	2162	1997	7513
San Joaquin 3	18	0	2216	2482	4716
South (CA)	4675	4391	3960	4786	17812
Spaulding 1	989	101	549	2135	3774
Spaulding 2	0	210	395	152	757
Spaulding 3	1760	2735	3623	3835	11953
Spring Gap	3955	3792	4327	4228	16302
Stanislaus	35273	36077	40249	40166	151765
Tiger Creek	29972	28886	30819	16240	105917
Toadtown	378	697	791	614	2480
Tule	2900	2329	3914	4412	13555
Volta 1	3051	3182	3750	4404	14387
West Point (CA)	10049	9332	20470	6656	46507
Wise	8683	8884	6620	7974	32161
Grand Total	976149	884699	1097666	1121560	4080074

Attachment H

Demand Forecast And Resource Plan Data: Disclosure Mandates Of The CPUC In R.04-04-025, Prepared By Dr. Michael Jaske, Energy Commission Staff.

Demand Forecast and Resource Plan Data: Disclosure Mandates of the CPUC in R.04-04-025

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California Energy Commission Staff
August 12, 2005

Summary

In parallel with the dispute between the California Energy Commission (CEC) and investor-owned utilities (IOUs) regarding the confidentiality protection to be afforded some aspects of the demand forecasts and resource plans that have been filed with the CEC as part of the 2005 Integrated Energy Policy Report (*2005 Energy Report*) proceeding, the California Public Utilities Commission (CPUC) has been addressing requests by intervenors in its proceedings to release similar data. The most relevant example is R.04-04-025, which is the avoided cost proceeding established to determine pricing for qualifying facility contracts in future years. A long series of data discovery disputes in this rulemaking were resolved by an Administrative Law Judge (ALJ) Ruling dated May 9, 2005. In this ruling, the assigned ALJ directed the IOUs to publicly distribute a significant amount of both supply and demand information, both historic and projected, on a quarterly or annual basis. Some of this information is the same that the IOUs are contesting release of in this *2005 Energy Report* proceeding. Thus, the CPUC's information disclosure decisions are relevant to the CEC Executive Director's aggregation proposal of June 3, 2005.

Background

In testimony filed July 8, 2005 in its appeal of the Executive Director's Notice of Intent (NOI), PG&E disputes the assertion in the NOI that substantial amounts of resource plan information have been required to be released to the public as a result of the Ruling. [Kuga, July 8, 2005, page 4] This paper describes the background, results and implications of this Ruling to the IOU appeals of the NOI to show that Kuga's testimony does not provide all of the relevant facts to judge the importance of this Ruling.

R.04-04-025 was initiated at the CPUC to address determination of avoided costs, with particular emphasis on the use of such avoided costs in setting contractual prices for qualifying facilities.[1] Intervenors in R.04-04-025 sought a large amount of information from IOUs that would assist them in making their own proposals for IOU avoided costs. Among this information were demand forecasts, resource plans, projected natural gas prices, projected wholesale electricity market prices, and large amounts of historic demand and resource information. As a general rule, the IOUs sought to minimize their responses to these data requests and/or to create a "protective order" mechanism in which the information would only be released to entities willing to enter into a non-disclosure

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[1] "Avoided costs" are those costs that a utility would have to expend to generate or acquire electricity. Under federal law, avoided costs are the basis of the payments made by utilities to suppliers that satisfy QF standards. In California, the CPUC established its own specific rules for determining avoided costs.

agreement with the IOU. The CPUC invested considerable time and some effort in attempting get the parties to resolve these disputes among themselves, but with limited success. In the end, the data discovery disputes were resolved by an ALJ Ruling dated May 9, 2005 (Ruling).[2] In general, the Ruling established two categories of data responses: (1) those which would be simply made public and distributed to the service list of the proceeding and/or a subset of interested parties, and (2) information to be made accessible only to those willing to sign a non-disclosure agreement as part of a protective order to guard against release to the general public.

Among the information sought by intervenors were demand forecasts, resource plans, and electric wholesale and natural gas price projections on a short time interval basis, e.g. monthly, daily and hourly.[3] As a general rule, the IOUs sought to block access to, and public distribution of, hourly and daily information. The IOUs alleged these were trade secrets that, if disclosed, would allow generators to "game" market transactions and generally increase costs to IOU bundled service ratepayers.

In the Ruling, ALJs Halligan and Thorson balance the interests of the intervenors and the degree of sensitivity of specific individual data. For example, the Ruling clearly states that hourly and daily versions of historic data can be readily used to determine the residual net short positions of the IOUs, potentially resulting in generators gaming bids into markets or responses to IOU procurement efforts. Thus, hourly and daily versions of the data are not to be publicly available. On the other hand, quarterly and annual versions of these same variables would not provide these opportunities and the ALJs directed that such versions of these information be made public without distribution restrictions.

Results of the Ruling

As a general rule, the Ruling directs release of quarterly/annual summaries of the underlying data, whereas daily/hourly versions of these same data are protected. Monthly summaries of these data are not addressed in most instances. To a considerable extent, this dichotomy between annual/quarterly versus daily/hourly is maintained regardless of whether the variable in question is actual historic, recorded values or forecasts of the future for these values or aggregates of them.[4]

In response, the IOUs actually submitted only a small fraction of the public information items. A subsequent ALJ ruling on June 14, 2005 compelled compliance with the initial order. The majority of the critical items were actually distributed on June 17, 2005, although some corrections and updates were filed on July 13, 2005. Another ALJ order

[2] CPUC, R.04-04-025, ALJ Halligan/Thorson Ruling, May 9, 2005. See http://www.cpuc.ca.gov/word_pdf/RULINGS/46194.doc

[3] Apparently, the intervenors plan to use these data to determine the level and pattern of avoided costs on a short term basis. Presumably, if these avoided cost patterns indicates that higher payments to qualifying facilities are appropriate, their owners (the intervenors) would argue that those cost patterns should be the basis for going-forward QF payments.

[4] In an attempt to avoid confusion, the word "information" will be used to describe summaries of values that are "data." For example, hourly load measurements for an LSE's customers are data. Aggregations of these hourly usage values into daily, monthly, quarterly or annual summaries are called "information."

resulted in filings from the intervenors on August 4, 2005 expressing grave concerns with the incomplete manner in which the IOUs responded to the previous ALJ rulings. Irrespective of the final outcome of these remaining disputes, substantial materials have already been made public.

Table 1 provides a summary of the requirements for public disclosure of the information most closely related to the resource planning information at dispute in the *2005 Energy Report* proceeding. Table 1 also identifies the way in which each IOU chose to respond. In some instances, the IOUs interpreted the requirements of the Ruling differently than the intervenors. The intervenors challenged these interpretations, leading to a supplemental data distribution on July 13. In some instances the IOUs seem to have provided more information than was required by a direct reading of the Ruling. The IOU data request responses sometimes reveal oral discussions between IOUs and intervenors that result in negotiated agreements to make mutually acceptable changes. Interestingly, the Ruling requires IOUs to provide as much or more in the near term (2005-2006) than the long term (2008 and beyond).

Table 2 summarizes which variables at issue in the IOU appeals of the NOI have been released as a result of IOU compliance with the May 9 Ruling.

Implications for the IOU/Energy Commission Dispute

Numerous items required to be released as a result of the May 9 Ruling are identical to those the IOUs seek to protect in their appeals of the Executive Director's aggregation proposals. Table 3 uses the exact format of the NOI for resource plan capacity summaries to show more precisely how the information disclosed as a result of the Ruling matches up with the aggregation proposal that has been appealed. While Table 3 is organized to show both capacity and energy, the vast majority of what the Ruling addresses are energy values, not capacity values. Thus the usefulness of the Ruling to resolution of the NOI appeals is principally on the quarterly energy values under dispute. The IOUs have not contested release of annual energy values summarized in this manner.[5]

The dispute over quarterly energy summaries for bundled customers that PG&E and SCE have made in their appeals should be conclusively resolved by two considerations. First, in some instances the CPUC May 9 Ruling requires IOUs to release precisely the same information items and, in fact, these have already been released to the public. Example of this are the quarterly energy demand forecast values explicitly ordered to be released, and were actually released on either June 14 or July 13, by all three IOUs. Second, in numerous instances the values ordered to be released by the Ruling cover forecast years 2005 or 2006, which (from the perspective of the IOU worried about market power) are more damaging than the 2009 to 2016 values proposed for release in the NOI. Similarly, the geographically aggregated quarterly energy summaries appealed by PG&E should be

[5] CEC Staff published annual energy summaries for IOU bundled customers in the Staff paper *Resource Plan Aggregated Data Results*, CEC Publication Number CEC-150-2005-001, June 2005.

resolved by the release of the bundled customer quarterly energy data, as the latter is more disaggregated than the geographically aggregated data.

In those instance where the May 9 Ruling directs the IOUs to release data for 2005 and 2006, while the NOI covers only 2009 - 2016, staff believe that the Ruling undercuts the IOU's arguments about potential harm to ratepayer interests resulting from the NOI. For the 2009 – 2016 period, conventional resource planning practices almost invariably assume average conditions due to the impossibility of predicting long-term weather patterns. On the other hand, climatological science is beginning to be able to predict one and two year ahead phenomena, so the CPUC mandate to release 2005 and 2006 hydro generation projections has much more potential to affect procurement outcomes than what the CEC's Executive Director has proposed.

Focusing specifically on the hydroelectric generation variable, which is central to PG&E's assertions about the need to protect quarterly energy data, the data PG&E has already disclosed are at the heart of the argument that it makes about the need to shield projections. [PG&E Appeal, June 17, 2005, page 3] Given what has been released, can PG&E continue to assert that these data can be classified as confidential because they are trade secrets? PG&E has already released 2003 and 2004 historic hydroelectric generation on a monthly basis. PG&E has already released its projections of 2005 monthly production from hydroelectric generation. Figure 1 plots these monthly data, both the actual information for years 2003 and 2004, and the projected values for 2005.

Obviously the 2005 values were projections that PG&E made when either all or most of 2005 was before them, and thus PG&E is revealing at least some portion of its thinking about the near-term future. Generators seeking to sell power to PG&E would certainly use this data to discern that they can expect smaller levels of purchases from PG&E in 2005 since hydroelectric generation is expected to be higher than in either 2003-2004 for all twelve months of the year. The month to month pattern is also somewhat different than either 2003 or 2004. Thus, those generators using such PG&E projections to guide how they respond to PG&E purchase requests could create some advantage compared to those generators not using this information. Whatever advantage this near-term disclosure has to generators and traders it is almost certainly more than the advantage such quarterly projections would provide for the period 2009-2016. In this long-term horizon, PG&E is not releasing anything but average hydroelectric generation patterns. Thus any impacts among competing generators or between generators and PG&E of the release of quarterly or monthly hydroelectric generation projections for the period of 2009-2016 is negligible compared to the impacts of the release of near-term 2005-2006 information.

Conclusion

The CEC staff believe that the IOU appeals of the Executive Director's proposal to release bundled customer and geographically aggregated quarterly energy data do not withstand scrutiny since much of the very data they seek to protect have already been released to the public, and the portions that have not been released are less likely to affect procurement outcomes than those which have been released via the Ruling.

Table 1
Summary of Public Disclosure of Demand Forecast and Resource Variables:
May 9, 2005 ALJ Ruling in R.04-04-003 and R.04-04-025

ALJ Direction and Page Citation	**IOU**	**IOU Response**	**Special Issues**
Projections			
Provide demand forecast on quarterly basis for 2006-2010 (page 27)	PG&E	Quarterly energy for 2006-2010	Provided 6/17
	SCE	Quarterly energy for 2006-2010 Monthly sales for 2002-2004 and forecast for 2005-2006 2005 coincident retail customer peak forecast, by class 2005 monthly energy forecast by SCE retail customer classes	Was not supplied until July 11 2005 monthly forecast provided in FERC Reliability Service Rate filing
	SDG&E	Quarterly net energy for 2005-2010 and reduction from gross sales of energy efficiency, DA, and self generation for 2009-2010	Provided partial response on 6/17 and more complete response on 7/13
IOU URG projections for 2005-2006 (page 29)	PG&E	Quarterly energy projections for 2005-2006 for the combined total of nuclear, fossil and hydro	Did not disaggregate by type of URG resource
	SCE	Quarterly energy projections for 2005 for each of nuclear, coal, and hydroelectric	
	SDG&E	Quarterly energy projections for 2005 for the combined total of nuclear and other types	Did not disaggregate by type of URG resource
Power plant Natural Gas Price Projections (pages 26, 29)	PG&E	Two 2004 vintage monthly gas price projections for 2005-2007 for North and South Calif border	
	SCE	Annual 2003-2020 gas price projections by scenario	
	SDG&E	Most recent natural gas price projections for 2006-2010	

ALJ Direction and Page Citation	IOU	IOU Response	Special Issues
		provided for nine different delivery points	
2005 - 2006 Monthly Supply-Demand Balance	PG&E	2005 and 2006 Monthly Supply-Demand Balances for energy enumerating all major resource categories	PG&E provided this monthly data in response to data request CCC 001-02, Supplement 01 For 2005 DWR contracts and RNS are withheld, and for 2006 addn'l items withheld are hydro and some bilateral contracts
	SCE	None	
	SDG&E	None	
Wholesale Electricity Price Projections (pages 25, 30)	PG&E	Annual 7x24 NP15 market prices for 2008-2027 projected using MultiSym	
	SCE	Annual wholesale market price projections 2003-2008 for multiple scenarios	
	SDG&E	Annual values for 2009-2010 provided, but most current projections for 2006-2008 withheld to be accessed only through protective order process	Updated July 13 to provide values for 2003 to 2010 from 2003 Resource Plan filing to CPUC
Historic Data			
Historical QF production by type and contract form (page 18)	PG&E	2003-2004 quarterly by thermal, non-thermal and 3 payment types	
	SCE	2003-2004 quarterly by cogeneration and renewables and for 3 payment types	
	SDG&E	2002-2004 annual by thermal and renewable and two payment types	

ALJ Direction and Page Citation	IOU	IOU Response	Special Issues
Historical Contract Purchase Volumes and Costs (page 21)	PG&E	2003Q1 – 2005Q1 for munies, merchants, and CAISO real time energy	
	SCE	Quarterly production and costs for each of short term market and long-term bilateral contracts for 2003Q1 – 2004Q4	
	SDG&E	Quarterly purchases and costs for 02Q1 to 05Q1 separated by long term bilateral contracts and short term/spot purchases	
Historical DWR Contract Deliveries (page 23)	PG&E	Quarterly DWR deliveries and costs for 03Q3 to 05Q1	
	SCE	Quarterly DWR deliveries and costs for 03Q1 to 04Q4	
	SDG&E	Quarterly DWR deliveries and costs for 02Q1 to 04Q1	7/13 filing revises most values submitted 6/17
RMR Costs (pages 22-23)	PG&E	Monthly RMR costs for 2002-2004 and RMR unit designations	
	SCE	Monthly RMR costs for 2002-2004 and RMR unit designations 2005 forecast of retail peak load by customer class and firm transactions with other utilities	 SCE's disclosure of retail peak was made to reveal allocation of RMR costs among LSEs
	SDG&E	Monthly RMR costs for 2002-2004 and RMR unit designations	

Table 2
Summary of CPUC-Mandated Disclosure and Implications for the for IOU/CEC Dispute

Variable/IOU	**Time Interval**	**Time Horizon**	**Implication for IOU/CEC Staff Dispute**
Energy demand forecast (all)	quarterly	2005-2010	Explicit release of variables PG&E and SCE oppose
Programmatic adjustments to base energy demand forecast (all)	quarterly	2005-2010	Explicit release of variables PG&E and SCE oppose
URG energy production (nuclear, fossil, hydro) (all)	quarterly	2005-2006	Explicit release of More “damaging” near term variables PG&E and SCE oppose
Hydroelectric generation (PG&E)	monthly	2005-2006	Explicit release of monthly hydro data that PG&E uses as rationale for its opposition
Historic generation by category of resources: DWR, QF, bilateral contracts and CAISO, RMR	quarterly	2003-2004 (SDG&E provides 2002 also)	Recent quarterly production provides a good basis for extrapolations to future years

Table 3
Disclosure Pursuant to May 9, 2005 Ruling Mapped into the Format of the ED's NOI Aggregation Summary

	PREVIOUS PUBLIC DISCLOSURE	
RESOURCE PLAN VARIABLE	**CAPACITY**	**ENERGY**
CUSTOMER DEMAND CALCULATIONS		
Reference Case Forecast	A 2005 (SCE)	Q 2006-2010 (all) M 2005-2006 PG&E
Load Adjustment(-)		M 2005-2006 PG&E
Uncommitted Price Sensitive DR Programs (-)		NA
Uncommitted Energy Efficiency (-)		Q 2006-2010 (all) M 2005-2006 PG&E
Distributed Generation (-)		Q 2006-2010 (all) M 2005-2006 PG&E
Net Demand for Bundled Customers		M 2003-2004 PG&E, SCE Q 2006-2010 (all) M 2005-2006 PG&E
Net Peak Demand + 15% Planning Reserve Margin		NA
Firm Sales Obligations		
Firm Resource Requirement		
Exist & Plan IOU RESOURCES		
Nuclear		M 2003-2004 PG&E, SCE Q 2005-2006 PG&E, SCE M 2005-2006 PG&E
Fossil		M 2003-2004 PG&E, SCE Q 2005-2006 PG&E, SCE M 2005-2006 PG&E
Hydro		M 2003-2004 PG&E, SCE Q 2005-2006 PG&E, SCE M 2005 PG&E
Total Utility-Controlled Physical Resources		M 2003-2004 PG&E, SCE Q 2005-2006 PG&E, SCE M 2005-2006 PG&E Q 2005 SDG&E
Exist & Plan CONTRACTUAL RESOURCES		
DWR Must-take Contracts		Q 2003-2004 (all)
QF Dependable Capacity		Q 2003-2004 (all) M 2005-2006 PG&E
Renewable Contracts		Q 2003-2004 (all) M 2005-2006 PG&E
Other Bilateral Contracts		M 2003-2004 PG&E, SCE Q 2003-2004 (all) M 2005-2006 PG&E
Short Term and Spot Market Purchases		Q 2003-2004 (all)
TOTAL Exist & Plan RESOURCES		
Existing Interruptible / Emergency (I/E)		NA

	PREVIOUS PUBLIC DISCLOSURE	
RESOURCE PLAN VARIABLE	**CAPACITY**	**ENERGY**
Programs		
Uncommitted Dispatchable Demand Response		NA
TOTAL CAPACITY + I/E and UDDR		
FUTURE GENERIC RESOURCE NEEDS		
Generic Renewable Resources		
Capacity of other Generic Additions		
Total Future Generic Resources		

A = annual, M = monthly, Q = quarterly.
(all) means that all three IOUs have provided this information.
(PG&E) means that PG&E provided this information.

Figure 1: Monthly PG&E Hydroelectric Generation